CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

APPENDIX 2-A:
DISTRIBUTION SYSTEM PLAN (2022-2026)

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1 INTRODUCTION

Canadian Niagara Power Inc. ("CNPI") has prepared this Distribution System Plan ("DSP") in accordance with the Ontario Energy Board's ("OEB's") *Chapter 5 Consolidated Distribution System Plan Filing Requirements* dated May 14, 2020 (the "Chapter 5 Requirements") as part of its 2022 Cost of Service Application (the "Application").

This DSP was prepared by CNPI employees and is supported by an Asset Management Program ("AMP") and area planning studies that were also prepared and updated by CNPI employees. The DSP is also supported by an Asset Condition Assessment ("ACA") completed by an independent third-party expert, METSCO Energy Solutions.

1.1 OBJECTIVES AND SCOPE

CNPI's DSP is a stand-alone document, updated on a 5-year cycle and filed in support of CNPI's cost of service applications. CNPI's DSP describes how the AMP, customer preferences, Area Planning Studies ("APS"), the ACA, and various other inputs have informed CNPI's actual and planned capital investments. The DSP documents the practices, policies and processes that are in place to ensure that investment decisions support CNPI's desired outcomes in a cost-effective manner and provide value to customers.

CNPI's DSP was developed with a focus on the four key performance outcomes included in the OEB's Renewed Regulatory Framework (RRF):

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.*

1.2 OUTLINE OF REPORT

This is CNPI's second DSP prepared in accordance with the Chapter 5 Requirements. This DSP describes how CNPI has developed, managed, and maintained its distribution system equipment to provide a safe, secure, reliable, efficient, and cost-effective service to its customers. The DSP identifies major initiatives and projects to be undertaken over the planning period. The DSP spans a 10-year period, with the historical period covering 2017-2021 (2021 being the Bridge Year) and the forecast period covering 2022-2026 (2022 being the Test Year).

The DSP contains four sections, including this introductory Section 1. Section 2 provides a high-level overview of the DSP, including coordinated planning with third parties and performance measurement for continuous improvement. Section 3 provides an overview of CNPI's asset management practices. Section 4 provides a summary of CNPI's capital expenditure plan, including an overview of the capital expenditure planning process, an assessment of the system capability for Renewable Energy Generation ("REG"), and justification of projects and programs with expenditures exceeding CNPI's rate base materiality threshold of $1.79 million.[1]

Where relevant, Sections 2 through 4 of the DSP are organized using the same section headings indicated in the Chapter 5 Requirements, with Chapter 5 heading numbers in parentheses. Other relevant information is included in separately identified sections (i.e. sections without equivalent Chapter 5 heading numbers) and is intended to complement the prescribed data.

1.3 DESCRIPTION OF THE UTILITY

CNPI is an OEB-licensed distributor (ED-2002-0572) serving approximately 26,200 customers within a 291 km^2 service area in the southern portion of the Niagara Region (Port Colborne and Fort Erie). While the Fort Erie and Port Colborne service areas are geographically adjacent, there are no electrical connections between the two areas due to historical differences in system voltage levels used within each area.

CNPI serves an additional approximately 3,600 customers within a 66 km^2 service area in and around Gananoque, operating as Eastern Ontario Power ("EOP"). The distribution system in Gananoque is supplied at 44 kV as an embedded distributor, and contains a significant amount of hydro-electric embedded generation.

Figure 1 shows the extent of CNPI's Fort Erie and Port Colborne service areas (along the northeast shoreline of Lake Erie), and CNPI's Gananoque service area (operating as EOP, northeast of Lake Ontario, along the St. Lawrence River). Additional descriptions of CNPI's service areas and distribution systems are provided in Section 2 of the AMP, included as Appendix A.

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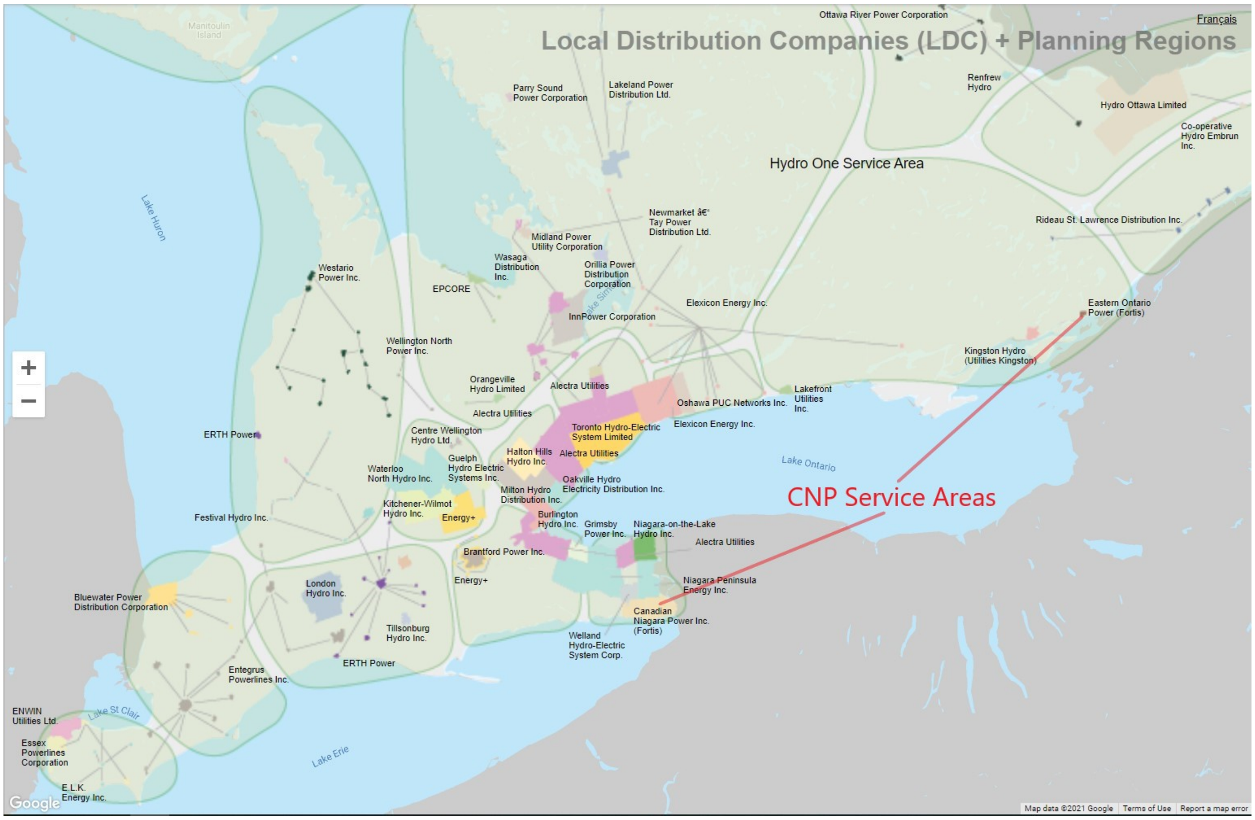
[1] CNPI's revenue requirement materiality threshold is identified as $100,000 in Exhibit 1. In consideration of CNPI's proposed Weighted Average Cost of Capital of 5.58% (see Exhibit 5), 2022-2026 capital investments of $100,000 / 0.0558 = $1.79 million (rounded) or more will lead to future revenue requirement impacts of $100,000 or more.

Figure 1: CNPI Service Areas (Southern Ontario Context)



1.3.1 CORE VALUES

CNPI has established seven core values that all employees should strive to promote and comply with each working day:

Respect for People

Treat others as you would have others treat you. Honesty, integrity and ethics are never compromised.

Inclusion and Diversity

Create a welcoming environment that encourages and promotes diversity, cross-culture working experiences and strong relationships with our Indigenous communities and partners. Demonstrate leadership and foster a workplace culture where all employees feel empowered to bring their authentic selves to the workplace, and do their best work.

Safety and the Environment

Demonstrate a personal, unrelenting commitment to safety and environmental excellence. Protect yourself, your fellow employees, the public, and the environment.

Financial Success

Produce solid earnings, with dividends that meet the expectations of CNPI shareholders. Grow shareholder value through prudent equity investments and business partnerships. Ensure that debt obligations are always met in a timely manner and to the satisfaction of our creditors.

Customer Service

Everyone has customers. Determine your customers' needs by listening. When you can meet those needs, do so; when you cannot, tell them you cannot – or tell them who can. When in doubt about how to treat a customer, do what you believe is right. When serving customers be pleasant, courteous and accurate; smile, act professionally and enjoy yourself…Attitudes are contagious.

Productivity

The old sayings hold true. Teamwork is key. Working smarter produces more gains than working harder. Mistakes are costly; get it right the first time. Job security comes from doing your job well, not from what job you do. Remember…if you have a better way to do something; just do it.

Community Involvement

Each of us has an obligation to support the communities that support our employer. This means time as much as money. Success is measured by the reaction of community leaders and the opinions expressed by community residents.

1.3.2 CUSTOMERS SERVED

CNPI serves approximately 30,000 residential and general service customers. In the last 5 years, CNPI's residential customer count has increased marginally each year (~1% or less each year), while general service customer counts are relatively flat.

Table 1: Residential and General Service Customer Counts[2]

Customer Class	2016	2017	2018	2019	2020
Residential	26,092	26,371	26,550	26,773	27,036
General Service < 50 kW	2,512	2,488	2,492	2,494	2,486
General Service >= 50 kW	204	197	203	188	196
Total Customers	**28,808**	**29,056**	**29,245**	**29,455**	**29,718**

[2] Customer counts in this table reflect December 31 counts, consistent with the OEB Yearbook of Electricity Distributors.

1.3.3 PEAK SYSTEM LOAD

Table 2 below lists CNPI's peak load over the past 5 years. CNPI's most recent load forecast confirms a gradual declining trend in the total annual energy delivered (wholesale kWh), with the only significant trend variable being related to persisting Conservation and Demand Management ("CDM") savings. Despite a decreasing trend in overall energy use, CNPI's peak system demand can vary significantly year-over-year based on weather extremes. Capacity ratings for most distribution assets depend on a combination of electrical loading and ambient temperature. As a summer peaking utility, CNPI must plan its distribution system to supply peak load coincident with maximum ambient temperatures. In 2020, for example, CNPI experienced its highest peak load in recent years on a day where the ambient temperature exceeded 34°C.

Table 2: Peak System Load

Total System Demand	2016	2017	2018	2019	2020
Winter Peak (kW)	80,952	76,432	80,586	78,312	75,663
Summer Peak (kW)	101,753	88,875	98,015	92,987	101,774
Average Peak (kW)	78,930	72,807	79,846	74,399	76,354

1.3.4 DISTRIBUTION SYSTEM ASSET SUMMARY

CNPI operates a total approximately 1,035 km of overhead primary and secondary line and 520 km of underground primary and secondary line in its Niagara and Gananoque service areas. CNPI's distribution lines include over 23,000 poles and over 4500 transformers of various types (pole-top, pad-mount and ratio bank).

CNPI also operates a total of 12 distribution substations (4 in Fort Erie, 5 in Port Colborne and 3 in Gananoque) as well as dozens of ratio banks to transform primary voltages to facilitate voltage conversion efforts and to supply lower density areas. Section 2.5 of CNPI's AMP, included as Appendix A, contains a detailed breakdown of CNPI's major distribution assets.

1.4 BACKGROUND AND DRIVERS

The Chapter 5 Requirements outline four categories of investments into which projects and programs must be grouped. The drivers for each investment category align with those listed in the Filing Requirements. For reporting purposes, a project or program involving two or more drivers associated with different categories is included in the category corresponding to the trigger driver. All drivers of a given project or program were considered in the analysis of capital investment options and are further described in Section 4 of the DSP.

Table 3: Drivers by Category for DSP Projects

Category	Driver	Capital Investments
System Access	Customer connections/upgrades; New subdivisions	Service connections/expansions; Transformers; Meters
	Third-party requests	Road relocations; Joint-use make-ready projects
System Renewal	Failure	Replacements due to asset failure, storm damage, vehicle accidents, etc.
	End of life (risk of failure)	Targeted pole replacement; Line rebuilds; Substation rebuilds; Other asset replacements
	End of life (functional, performance, reliability)	Voltage conversion; Substation rebuilds/replacements
System Service	Reliability, capacity, operating efficiency, loss reduction	Voltage conversion; Substation upgrades, reconfiguration
	Reliability improvements	Distribution automation; Protection & Control upgrades; Fault indicators; Wildlife guards
General Plant	System maintenance and investment support	IT Hardware/Software; Fleet; Tools and Equipment; Communication assets; Facility renovations Land rights, easements;
	Business operations efficiency	IT Hardware/Software; Business system integration/upgrades; Electric vehicles

System Access

These investments are modifications to the distribution system CNPI is obligated to perform to provide a customer or group of customers with access to electricity services via CNPI's distribution system. This category also includes asset relocations in accordance with applicable legislation.

System Renewal

These investments involve replacing assets at end of life and/or refurbishing system assets to extend the original service life, thereby maintaining the ability of CNPI's distribution system to provide customers with safe and reliable service.

System Service

These investments are modifications to CNPI’s distribution system to ensure the distribution system continues to meet CNPI’s operational objectives and its customer’s expectations with respect to reliability.

General Plant

These investments are modifications, replacements or additions to CNPI’s assets that are not part of the distribution system; including land and buildings, tools and equipment, and electronic devices and software used to support day-to-day business and operations activities.

2 DISTRIBUTION SYSTEM PLAN (5.2)

Section 2.1 provides an overview of the DSP, Section 2.2 summarizes coordinated planning activities with third parties, and Section 2.3 covers performance measurements to continuously improve asset management and Capital Expenditure planning processes.

2.1 DISTRIBUTION SYSTEM PLAN OVERVIEW (5.2.1)

The following sections provide the OEB and stakeholders with a high-level overview of the information filed in the DSP, including key elements of the DSP, sources of expected cost efficiencies, the period covered by the DSP, the vintage of the information, an indication of important changes to CNPI's asset management processes, and aspects of the DSP that are contingent on the outcome of ongoing activities or future events.

2.1.1 KEY ELEMENTS OF THE DSP (5.2.1A)

CNPI has prepared a 5-year investment plan that considers and balances the following inputs and objectives:

- Meeting the objectives of CNPI's system planning process, as described in Section 4.2.1.
- Responding to the preferences of CNPI's customers, as identified through customer engagement activities and summarized in Section 2.1.2.
- Addressing system performance and contingency risk issues, based on the results of CNPI's APS, which is included as Appendix E.
- Addressing asset end of life replacements, based on the results on CNPI's ACA, which is included as Appendix D.
- Addressing a number of key challenges identified by CNPI, as described in Sections 2.1.1.1 through 2.1.1.5 below.
- General plant investments sufficient to support the identified distribution system capital investments and asset maintenance requirements, and to support CNPI's daily operations activities.

The key challenges outlined in the following sections provide insight into factors that led to CNPI's decision to accelerate voltage conversion and reliability-driven investments over the historical period, and factors that continue to be addressed by the investments that CNPI has proposed for the forecast period.

2.1.1.1 KEY CHALLENGE: SYSTEM VOLTAGE LEVELS

The extensive 2.4/4.16 kV system in CNPI's Port Colborne, Stevensville (part of Fort Erie) and Gananoque service areas is the lowest distribution voltage level still commonly in use in Ontario. While the presence of nearby 27.6 kV and 34.5 kV feeders ensures that new customers can readily be connected, the extensive 2.4/4.16 kV systems still in use result in high distribution system losses as well as capacity constraints during certain system contingencies. The legacy 4.8 kV distribution system in parts of Fort Erie has similar challenges related to losses and contingency options, with additional safety and reliability risks due to the delta-connected nature of this system.

In the Niagara area, the historical selection of different distribution voltage levels in Fort Erie (4.8 kV and 34.5 kV) and Port Colborne (4.16 kV and 27.6 kV) makes it impractical to standardize system voltages and provide interconnections between these adjacent service areas. While the 34.5 kV system in Fort Erie is able to transmit electricity over long distances with low losses and minimal voltage drop, it is also higher than common primary distribution voltage levels throughout Ontario, such that a full-scale conversion to this voltage level would not be cost-effective due to the high cost of distribution line equipment. CNPI has been actively converting its 4.8 kV Delta system to a 4.8/8.3 kV Wye system over a number of years, using ratio banks in many cases to supply different voltage levels as conversion efforts progressed. This voltage conversion program improves feeder capacity, reduces voltage drop and line losses, reduces the safety concerns caused by the delta configuration, and was justified during CNPI's 2017 cost of service application. As this conversion effort ramped up over the historical period (2017-2021), CNPI began to experience reliability issues with ratio bank installations, and also began to experience higher customer growth within the Fort Erie service area. Reassessment of safety, reliability, contingency risk and system performance led CNPI to make the decision to accelerate the pace of its voltage conversion program in 2018, with a focus on the Fort Erie service area.

The scope of voltage conversion efforts is somewhat different in the Port Colborne and Gananoque service areas, where conversions are from 2.4/4.16 kV to 16/27.6 kV. Unlike in the Fort Erie 4.8 kV conversions, these conversions require complete replacement of all line hardware and distribution transformers. In cases where the 27.6 kV system is already overbuilt or adjacent to the 4.16 kV system, these voltage conversions are relatively straightforward and cost effective. Conversely, in cases where there are no 27.6 kV feeders nearby, voltage conversions would have to work outwards from the nearest 27.6 kV feeder, making it difficult to align conversion efforts with end-of-life asset replacements without installing a large number of temporary ratio banks.

A combination of substation end-of-life considerations, detailed system planning studies including consideration of contingency risk, and challenges with obtaining land for construction of new substations have led CNPI to reconsider its substation and voltage conversion strategies for its various 4.16 kV systems, as detailed in CNPI's APS (Appendix E).

Completion of voltage conversion programs will gradually increase CNPI's system capacity and performance, improve contingency planning options, and lead to reduced system losses.

2.1.1.2 KEY CHALLENGE: LOW DENSITY

In terms of customer density (e.g. customers per km of line and customers per square km of service area), CNPI ranks in the lowest quartile among LDCs in Ontario. CNPI's combined service areas cover 357 square kilometres, approximately 80% of which is rural.

From a reliability perspective, the rural portions of CNPI's service area are generally served by longer distribution feeders, which are exposed to a higher number of trees per km than in urban/suburban settings. The distance between substations and the number of radial line segments limits load transfer and restoration options during outages. Voltage conversion programs that are in progress further limit CNPI's contingency options, since substations or feeders that might otherwise provide an alternate supply to a particular area operate at different voltage levels for a period of time. Ratio banks deployed during voltage conversion efforts are also generally designed without redundancy and are less reliable overall compared to traditional substations.

CNPI's system planning efforts consider long-term integrated solutions for voltage conversion and substation planning to identify and resolve system capacity and contingency limitations, including low-density areas where planning decisions and changes in load could significantly affect future contingency options. The results of CNPI's APS indicate that acceleration of voltage conversion and continued investment in certain substations will significantly reduce contingency risk and improve system performance.

2.1.1.3 KEY CHALLENGE: LAND AVAILABILITY FOR SUBSTATIONS

CNPI's prior DSP included a project to construct a new dual-element Port Colborne South DS that would allow end-of-life assets at two existing substations (Jefferson DS and Catharine DS) to be retired. Despite the general low-density characteristics of much of CNPI's service areas, suitable land for construction of new substations could not be secured in the downtown Port Colborne area.

Rather than pursuing expensive and time-consuming processes to expropriate land for the new substation, CNPI has rebuilt the two existing single-element substations and re-evaluated options for contingency planning in this area.

CNPI faced similar land availability challenges in downtown Gananoque to construct a new substation that would allow retirement of the Gananoque DS, leading to an alternative solution to distributed step-down transformation across multiple smaller pad-mounted transformers.

Further detail related to contingency assessment and options is provided in the APS and further detail on capital investments is provided in Sections 4.3 and 4.4.

2.1.1.4 KEY CHALLENGE: STORM DAMAGE

CNPI has experienced an increasing frequency of severe storms causing widespread outages and severe damage to its distribution system. A summary of CNPI's Major Event Day ("MED") classifications and the resulting effect on reliability statistics is provided in Section 2.3.1.1.

The acceleration of voltage conversion, distribution automation and other capital investment in recent years will help to reduce the outage impact associated with these storms, due to newer assets being able to better withstand weather effects. These investments will also help improve CNPI's outage response efforts, through automated restoration schemes and increased redundancy and availability of alternate supply paths as voltage conversion projects are completed.

Further, CNPI has begun exploring changes to design criteria and standards, with a focus on considering storm-hardened designs and/or additional redundancy in its capital investment planning. Storm-hardened designs include increasing the use of underground cable where practical, and adjusting the relative mechanical strength properties between wood poles and overhead conductors to reduce the extent of damage from falling trees. The initial focus for these efforts includes areas with the highest likelihood of experiencing significant damage combined with difficult restoration.

2.1.1.5 KEY CHALLENGE: ECONOMIC AND LEGISLATIVE UNCERTAINTY

Subdivision developments in CNPI's service area increased significantly over the 2017-2019 period, before trailing off in 2020 as a result of the COVID-19 pandemic. At this point in time, CNPI is not certain how quickly, or to what level, residential housing activity will ramp up in its service area post-pandemic.

Related to post-pandemic uncertainty is housing activity, CNPI anticipates that infrastructure plans related to roads and bridges could change significantly as the province reopens, particularly if economic recovery and stimulus programs include a focus on increased infrastructure spending.

Further adding to the level of uncertainty in externally driven projects, the recently enacted *Building Broadband Faster Act, 2021*, and pending regulations under that act, could drive a large volume of joint-use activity, particularly in CNPI's more rural areas.

CNPI has forecasted a level of System Access investments that recognizes an overall increased level of activity compared to the forecasts provided in its previous DSP. From a resourcing and supply perspective, CNPI recognizing that increased levels of engagement with government agencies, municipalities, road authorities and developers will be required to ensure that CNPI is prepared to respond to changing levels of externally driven projects over the forecast period.

2.1.2 OVERVIEW OF CUSTOMER PREFERENCES AND EXPECTATIONS (5.2.1B)

CNPI employs a variety of communication channels to inform and engage with its customers, employees, communities, other stakeholders and third parties on a regular basis. This includes regular bill inserts, presence on social media platforms, website updates, customer portals, community and contractor meetings, participation in regional planning efforts, and participation in community events.

In order to engage with customers specifically in relation to this DSP, CNPI worked with UtilityPULSE to review the findings and trends from prior customer surveys and create two online surveys designed to gather wisdom, information, feedback and insights from respondents. The results of these surveys indicate broad support across all capital investment categories, with anywhere from 61 to 94% of survey respondents supporting investments levels at or above the amounts presented in the surveys. With respect to increased tree trimming to reduced tree-caused outages, the majority of respondents supported increased spending, but at a level less than originally proposed by CNPI. Median support for the overall rate increasing resulting from CNPI's 2022-2026 DSP was slightly below the result that would have resulted from the investment plan and tree trimming increases originally proposed by CNPI.

In response to customer preferences related to rate increases, CNPI kept overall investment levels and tree trimming increases consistent with levels that were supported by the majority of customers.

Further, CNPI ensured that its online surveys were designed to identify and prioritize both overall priorities and customer care priorities. Three key themes emerged as priorities for the majority of CNPI's customers:

- Any category of investment intended to maintain or improve reliability was supported by the majority of customers.
- 81% of customers identified preventing data and system breaches as a priority.
- Reducing CNPI's environmental footprint is a priority for most customers, including increased use of e-billing and other paper-free communication, and education on energy conservation.

Three additional categories of customer care improvements were also identified as priorities:

- Automated outage notification messages and other alerts
- Self-serve options and online forms
- Education on energy conservation

Sections 4.1.3 and 4.2.2.1 provide additional detail on the results of CNPI's customer engagement surveys and how customer preferences are considered in CNPI's overall capital planning process.

2.1.3 ANTICIPATED SOURCES OF COST SAVINGS (5.2.1C)

CNPI's capital investments over the 2017-2021 historical period, combined with proposed investments over the 2022-2026 forecast period are expected to result in the following sources of cost savings:

Reduction in System Losses

All else being equal, converting load from 4.8 kV Delta to 4.8/8.3 kV Wye in Fort Erie and converting 2.4/4.16 kV load to 16/27.6 kV in other areas will reduce CNPI's overall system losses.

Any savings from line loss reductions between rate applications will flow to customers through clearing of variance accounts related to any cost of power components where the line loss factor is applied to billed quantities.

Proactive vs. Reactive Asset Replacements

CNPI has addressed, and continues to address, a significant volume of end-of-life asset replacement requirements. CNPI expects that investments will continue to shift away from reactive replacements (e.g. one-off pole replacements upon failure or identification of major deficiencies) to more proactive replacements that balance the overall planning objectives described in this DSP. Proactive replacement projects generally allow for increased assessment of alternatives and for more cost-effective mobilization of material, equipment and crews.

Efficiency and Operational Improvements from Business Systems

Advancements in business system platforms and increased integration between systems continues to provide a number of efficiency and operational improvements:

- Integration between AMI and OMS systems has increased awareness of power outages and improved visibility into the likely source of the outage locations, allowing more efficient deployment of field crews and more effective communication with customers. Mobile tools allowing operations crews to directly access this information in the field will be tested to further improve outage response.
- Increased integration between metering data systems and engineering analysis software allows for more accurate assessment of system loading and performance, increasing CNPI's ability to align investments between asset end of life requirements and investments aimed at addressing loading or performance issues.
- CNPI's 2021 pole testing program is piloting the use of a mobile data entry interface that will upload results directly into the GIS system, reducing manual effort and improving CNPI's ability to analyze results for system planning purposes.
- Implementation of a new customer portal will allow for increased use of self-serve options and web-based forms to improve the customer experience while reducing administrative and record-keeping effort.
- Cloud-based solutions are being explored to increase the performance and cost-effectiveness of various IT systems and to reduce IT hardware costs.

2.1.4 PERIOD COVERED BY DSP (5.2.1D)

The planning horizon for this DSP covers ten years with a 5-year historical period of 2017 to 2021, where 2021 is the Bridge Year, and a 5-year forecast period of 2022 to 2026, where 2022 is the Test Year.

2.1.5 VINTAGE OF THE INFORMATION (5.2.1E)

CNPI's third-party Asset Condition Assessment (ACA) was initiated in mid-2020, based on the most recently available asset inspection and condition assessment data (e.g. the ACA considered the most recently available month inspections from 2020, most recent available inspection results from prior years for annual or multi-year programs, pole testing results where available, etc.). Asset inspection and maintenance intervals are described in detail in CNPI's AMP, included as Appendix A. While the ACA report (Appendix D) was issued in October 2020, the health indices contained within that report reflect some degree of lag based on the underlying inspection and maintenance cycles.

Unless otherwise noted, all other information contained in this DSP is current as of December 31, 2020.

2.1.6 IMPORTANT CHANGES TO ASSET MANAGEMENT PROCESSES (5.2.1F)

CNPI has developed a comprehensive AMP, which is included as Appendix A to this DSP. The AMP provides a high-level overview of CNPI's distribution system and managed electrical assets, with detailed information on the inspection and maintenance programs by asset type, as well as the planning and condition assessment processes by which these assets are managed. Continuation of programs such as pole testing, infrared scanning and dissolved gas analysis have improved CNPI's ability to more accurately assess the condition of in-service assets. Also, CNPI has contracted METSCO to formalize the ACA component of its asset management process and to make recommendations on improvements to its asset management practices. During the 2022-2026 period, CNPI expects to evaluate and prioritize recommendations for improved data collection in Section 4 of the ACA report with the goal of improving the granularity of the Health Index values used to prioritize asset maintenance and replacement. CNPI also expects that continued integration of business systems such as SAP, GIS, OMS and SCADA can provide improved analytic capabilities to assist with project prioritization within the programs identified in the current 5-year DSP.

2.1.7 DSP CONTINGENCIES (5.2.1G)

Investments in the System Access category are generally driven by future and current customers as well as external parties. The uncertainties related to housing activity, recent broadband-enabling legislation, and post-pandemic economic recovery and stimulus programs discussed in Section 2.1.1.5 above could result in significant variation in System Access investment levels over the forecast period.

CNPI has not forecasted any REG-specific investments for the 2022-2026 period, based on a current policy environment that provides limited incentives for the installation of new sources of embedded generation. In the event that a combination of Government or OEB policy changes, technological developments, or economic factors results in a large increase in REG connection requests, CNP may be required to undertake REG-specific investments beyond those forecasted in this DSP in order to allow the requested connections to proceed.

2.1.8 GRID MODERNIZATION, DISTRIBUTED ENERGY RESOURCES & CLIMATE CHANGE ADAPTATION (5.2.1H)

CNPI continues to invest in grid modernization programs including significant investments in SCADA-capable equipment and distribution automation schemes. Combined with investments in voltage conversion and substation rebuild programs, CNPI's distribution system is expected to operate more reliably, more efficiently, and with a greater capability for connected complex loads and distributed energy resources as advancements in technology and emerging policy encourages such connections.

2.2 COORDINATED PLANNING WITH THIRD PARTIES (5.2.2)

2.2.1 SUMMARY OF CONSULTATIONS (5.2.2A)

CNPI has been an active participant in the regional planning process led by Hydro One Networks Inc. (HONI) for both its Niagara and Gananoque service areas, as summarized in Sections 2.2.1.1 and 2.2.1.2 below. In Section 2.2.1.3, CNPI has also included a summary of coordinated local efforts with Hydro One on projects to address CNPI-specific requirements.

Within the 2022-2026 period covered by the DSP, CNPI anticipates that additional coordinated planning activities with Internet Service Providers will be required as a result of the *Supporting Broadband and Infrastructure Expansion Act, 2021*. Since development of regulations, identification of priority broadband projects, and consideration of funding mechanisms were still pending at the time of finalizing this DSP, CNPI has not forecasted any specific investments related to these projects, but has provided additional discussion under Section 2.1.7 (DSP Contingencies) above.

2.2.1.1 REGIONAL PLANNING PROCESS – NIAGARA (5.2.2A-C)

The Fort Erie and Port Colborne portions of CNPI's service area are included in the Niagara Region for regional planning purposes.

HONI initiated the first cycle of regional planning for the Niagara Region with a Needs Assessment on October 15, 2015. CNPI, along with a number of other LDC's and the IESO participated in the Needs Assessment process. The first cycle Regional Infrastructure Plan (RIP) report, which was published in March 2017, outlined a number of transmission projects with no cost implications for CNPI.

HONI initiated the second regional planning cycle for the Niagara Region in March 2021 and HONI published a Needs Assessment report on May 24, 2021. Based on the Needs Assessment, CNPI does not anticipate material cost implications resulting from any of the identified projects. A letter of comment from Hydro One, included as Appendix B, outlines CNPI's participation in the regional planning process for Niagara.[3]

2.2.1.2 REGIONAL PLANNING PROCESS – PETERBOROUGH TO KINGSTON (5.2.2A-C)

The Gananoque portion of CNPI's service area, where CNPI operates as Eastern Ontario Power (EOP) is included in the Peterborough to Kingston Region for regional planning purposes.

HONI initiated the first cycle of regional planning for the Peterborough to Kingston Region with a Needs Assessment on December 12, 2014. The Needs Assessment for the Peterborough to Kingston Region recommended that all identified needs (none of which impacted EOP) be addressed either through a

[3] The planning status letter from HONI does not directly address the Needs Assessment from the second cycle of regional planning for the Niagara Area, which was published after the letter was issued, but prior to CNPI filing its 2022 cost of service application.

Local Plan or through Bulk System Planning, and concluded that no further regional coordination was required for the 2014-2023 period.

HONI initiated the second regional planning cycle for the Peterborough to Kingston Region with a Needs Assessment on December 9, 2019. The Needs Assessment identified overloading concerns for the Frontenac TS, which supplies EOP as an embedded distributor to HONI. In the short term, the study team recommended that the overloading could be managed by HONI and Kingston Hydro coordinating load transfers between two substations. The study team also recommended initiating an Integrated Regional Resource Plan and/or a Regional Infrastructure Plan to address this need, among others, in the longer term. None of the identified transmission projects are expected to require capital contributions from EOP.

2.2.1.3 CNPI-SPECIFIC COORDINATION WITH HYDRO ONE (5.2.2A-C)

An increasing frequency and duration of loss of supply outages to the Gananoque area became an emerging issue at the time of CNPI's previous cost of service rate application in 2016. CNPI undertook significant engagement with the Town of Gananoque and Hydro One in 2016 and 2017 to focus on cost-effective solutions for improving the reliability of the Hydro One 44 kV supply. CNPI also prioritized pole testing efforts in this area. As a result of these efforts, CNPI identified an opportunity to replace a large numbers of end-of-life use poles on a portion of CNPI's West Line that were also joint-use poles for Hydro One's 44 kV supply. Additionally, CNPI worked with Hydro One to install new switches between its M8 supply feeder and another nearby 44 kV feeder to provide an alternative supply path that could be used following outages on approximately half of the Hydro One feeder supplying Gananoque.

CNPI also experienced increasing loss of supply outages to its Port Colborne service area leading up to 2018. CNPI again worked cooperatively with Hydro One to identify the root causes of outages and develop solutions. As a result of these coordination efforts, Hydro One ultimately advanced a planned rebuild of its Port Colborne TS and energized a previously idled transmission line to provide an alternate source of supply.[4] CNPI also made additional investments in its distribution lines near the Port Colborne TS in order to accommodate Hydro One's advancement of this project.

2.2.2 REG INVESTMENTS AND IESO COMMENT LETTER (5.2.2D)

Based on CNPI's anticipation that 2022-2026 REG connections will be limited to a small number of net metering and load displacement projects (see Section 3.4.2), and its assessment that its distribution system would be able to accommodate any such projects (see Sections 3.4.3 to 3.4.5), CNPI has not included any REG-specific investments in this DSP. The IESO has commented in recent rate applications that no letter of comment is required from the IESO in circumstances where a distributor is not

[4] See the joint HONI/CNPI news release related to the significant investments to improve reliability to Port Colborne: https://www.cnpower.com/sites/cnpower.com/files/News%20Release_Port%20Colborne_Final_v2.pdf

proposing REG investments during the DSP forecast period, and CNPI has therefore not requested IESO comments.[5]

2.3 PERFORMANCE MEASUREMENT FOR CONTINUOUS IMPROVEMENT (5.2.3)

CNPI compiles a variety of performance-based reports for performance monitoring and analysis and/or submission to the OEB on a regular basis. This includes items such as reliability statistics and Electricity Service Quality Regulation (ESQR) reports. As these reports are compiled, they are reviewed to determine if any failure to meet target performance levels, any trending in performance requires corrective action, or any adjustments to future capital or maintenance programs. Performance measures included in these reports are divided into three groups:

- customer oriented performance;
- cost efficiency and effectiveness; and
- asset/system operations performance

Most of these performance measures are included on CNPI's OEB scorecard, which establishes minimum levels of performance expected to be achieved by CNPI. The scorecard is designed to track CNPI's historical performance, to identify trends in performance and whether targets are met, and to present results and trends in a manner that is easy for customers to understand. The associated Management Discussion and Analysis requires CNPI to provide additional explanation related to the results and trending for each scorecard performance metric. Performance as compared to targets and historical trends are considered in CNPI's asset management process. CNPI's 2019 scorecard is attached in Appendix C.[6]

Table 4 below summarizes CNPI's performance measures and Targets, with additional detail corresponding to Sections 5.2.3 (a)-(d) of the Chapter 5 Filing Requirements provided for each specific performance measure throughout Sections 2.3.1-2.3.3.

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[5] In 2019, the IESO confirmed by email to Algoma Power Inc. (an affiliate of CNPI) that: *"Under the circumstances of Algoma not having REG investments over the DSP period 2020-2024, no letter from the IESO is required, as the requirement is for when there are investments."* Similarly, CNPI has reviewed a number of 2021 rate applications and determined that the IESO has taken similar positions where no REG investments are included in the DSP.
[6] Note that CNPI's OEB scorecard also contains performance measures related to financial ratios that are not discussed in this DSP. See CNPI's Business Plan (Exhibit 1, Appendix B) for discussion of these measures.

Table 4: Performance Measures and Targets

Performance Outcome	Measure	Metric	CNPI Target
Customer-oriented performance	Service Quality	New Residential/Small Business Services Connected on Time	>90%
		Scheduled Appointments Met On Time	>90%
		Telephone Calls Answered On Time	>65%
	Customer Satisfaction	First Contact Resolution	>95%
		Billing Accuracy	>98%
		Customer Satisfaction Survey	> Ontario Benchmark
	System Reliability	SAIDI	<2.26
		SAIFI	<2.21
Cost efficiency and effectiveness	Cost Control	Total Cost Benchmarking Efficiency Assessment	Improving Trend per OEB PEG Model
Asset, system, operations performance	Safety	Level of Public Awareness	Increasing Trend
		Level of Compliance with Reg 22/04	Compliant
		Serious Electrical Incident Index	0
	Distribution Losses	Distribution System Losses	Decreasing Trend

2.3.1 CUSTOMER-ORIENTED PERFORMANCE

2.3.1.1 SERVICE QUALITY

2.3.1.1.1 METHODS AND MEASURES (5.2.3A)

CNPI measures and reports on an annual basis on each of the service quality requirements set out in the Distribution System Code (DSC). Failure to meet minimum service quality targets, or declining trends in performance, would result in measures being taken to realign performance with DSC service quality standards. Three service quality measures are included on the OEB scorecard: New Residential/Small Business Services Connected on Time, Scheduled Appointments Met on Time and Telephone Calls Answered on Time. All these measures are self-explanatory in nature and all relate to CNPI providing connection services as well as quality customer service. CNPI is committed to meeting and exceeding all targets found in the Service Quality performance measure group.

2.3.1.1.2 HISTORICAL PERFORMANCE (5.2.3C)

CNPI has consistently met its target for each service quality performance measure. Table 5 presents the historical results for the scorecard service quality measures tracked and reported by CNPI.

Table 5: Performance Measures – Service Quality

Metric | Target	2016	2017	2018	2019	2020
Low Voltage Connections | > 90%	91.10%	90.81%	90.40%	93.27%	94.91%
Appointments Met | > 90%	100.00%	100.00%	100.00%	100.00%	100.00%
Telephone Accessibility | > 65%	75.70%	77.33%	80.98%	79.73%	79.79%

2.3.1.1.3 PERFORMANCE TREND INTO THE DSP (5.2.3D)

CNPI has consistently exceeded targets with respect to service quality measures and expects to continue to meet or exceed these targets throughout the forecast period.

2.3.1.2 CUSTOMER SATISFACTION

2.3.1.2.1 METHODS AND MEASURES (5.2.3A)

Customer Satisfaction performance measures reported by CNPI include: First Contact Resolution, Billing Accuracy and Customer Satisfaction Survey Results. CNPI's target for Billing Accuracy is aligned with OEB's target of 98%.

CNPI measures First Contact Resolution performance by tracking the number of escalated calls as a percentage of total calls taken by the customer service center. CNPI strives to have less than 1% of total calls escalated, consistent with historical performance.

CNPI conducts annual customer surveys and engages in a large variety of consultation activities with customers and stakeholders. The feedback obtained through these activities provides CNPI with a sense of customer preferences that can be considered in both short-term and long-term plans. CNPI's target is to meet the needs and identified priorities of its customers as identified through surveys and engagement. CNPI considers historical performance and Ontario benchmarks in evaluating its annual satisfaction scores. As summarized in Section 2.1.2 and further detailed in Section 4.1.3, in addition to annual satisfaction surveys, CNPI conducted more extensive customer engagement surveys specific to this DSP and the results of those surveys have informed the development of the DSP.

2.3.1.2.2 HISTORICAL PERFORMANCE (5.2.3C)

Customers continue to rate CNPI very high in terms of overall customer satisfaction, and CNPI consistently exceeds OEB metrics for customer satisfaction, as illustrated in the following table.

Table 6: Performance Measures – Customer Satisfaction

Metric | Target	2016	2017	2018	2019	2020
First Contact Resolution | > 99%	99.20%	99.80%	99.84%	99.94%	99.92%
Billing Accuracy | > 98%	99.81%	99.91%	99.90%	99.92%	99.95%
Customer Satisfaction Survey Results	85%	91%	91%	91%	92%

2.3.1.2.3 PERFORMANCE TREND INTO THE DSP (5.2.3D)

CNPI has consistently exceeded targets with respect to First Contact Resolution and Billing Accuracy metrics and expects to continue to meet or exceed these targets throughout the forecast period.

Further details of the recently completed customer engagement surveys specific to this DSP, along with discussion of how CNPI's planned investments for the 2022-2026 forecast period have considered the needs of its customers, is provided in Section 4.1.3.

2.3.1.3 SYSTEM RELIABILITY

2.3.1.3.1 METHODS AND MEASURES (5.2.3A)

System reliability is an indicator of quality of electricity supply received by the customer. System reliability and performance is monitored by CNPI on a monthly basis, with detailed annual filings of reliability results provided to the OEB.

The reliability of supply is primarily measured by internationally accepted indices SAIDI and SAIFI as defined in the OEB's Electricity Reporting & Record Keeping Requirements dated March 31, 2020. SAIDI, or the System Average Interruption Duration Index, is the combined length of outages that the average customer experiences in the year, expressed as hours per customer per year. It is calculated by dividing the total customer hours of sustained interruptions over a given year by the average number of customers served. SAIFI, or the System Average Interruption Frequency Index, is the number of interruptions that the average customer experiences in the year, expressed as the number of interruptions per year per customer. It is calculated by dividing the total number of sustained customer interruptions over a given year by the average number of customers. An interruption is considered sustained if it lasts for at least one minute.

$$SAIDI = \frac{Total\ customer\ hours\ of\ sustained\ interruptions}{Average\ number\ of\ customers\ served}$$

$$SAIFI = \frac{Total\ customer\ interruptions}{Average\ number\ of\ customers\ served}$$

Loss of supply outages occur due to problems related to transmission assets that are not owned by CNPI. CNPI tracks SAIDI and SAIFI including and excluding loss of supply. Major Event Days (MED) are calculated using the IEEE Std 1366-2012 methodology. In accordance with OEB requirements, MED's also require an assessment of whether major interruptions were beyond the control of CNPI (i.e. force majeure or loss of supply) and whether the interruption was unforeseeable, unpredictable, unpreventable, or unavoidable. MED outages may include outages caused by loss of supply, as well as outages resulting from other causes. Once a particular calendar day is identified as meeting these criteria, all outages occurring on that calendar day are reported as MED outages, regardless of cause code. This practice reflects the reality that during a major event, all of CNPI's available resources (and often additional third-party resources) are fully deployed in response to the major event, causing delays in responding to coincidental outages that may be unrelated to the major event.

CNPI's system interruption reports contain detailed information on outage location, cause, equipment involved, and customers impacted. There is also a section where recommendations and comments can be made by the operational staff involved in outage response where they believe that follow up by other departments is warranted. As the outage records are populated in CNPI's outage database, copies are also circulated to any department flagged for follow up action. This ensures that specific issues of concern (e.g. repeated failure of a certain type of equipment, forestry concerns on a specific line section, etc.) are routed to the department that can most adequately resolve the issue.

2.3.1.3.2 HISTORICAL PERFORMANCE (5.2.3C)

SUMMARY

CNPI's reliability indices for 2016-2020 are provided in Table 7, with Figure 2 and Figure 3 illustrating CNPI's 5-year SAIDI and SAIFI trends.

Table 7: 2016-2020 Reliability Metrics

Index	Incl outages caused by loss of supply					Excl outages caused by loss of supply					Excl Loss of Supply and Major Event Days				
	2016	2017	2018	2019	2020	2016	2017	2018	2019	2020	2016	2017	2018	2019	2020
SAIDI	5.710	9.650	11.700	11.380	7.140	3.470	3.830	3.740	10.220	5.070	3.466	3.111	2.448	3.006	2.730
SAIFI	4.030	5.280	6.530	3.480	4.840	2.290	2.330	2.730	3.080	2.710	2.292	2.044	2.141	2.001	2.190

5 Year Historical Average

SAIDI		9.116		5.266		2.952
SAIFI		4.832		2.628		2.134

Figure 2: 2016-2020 SAIDI Trends

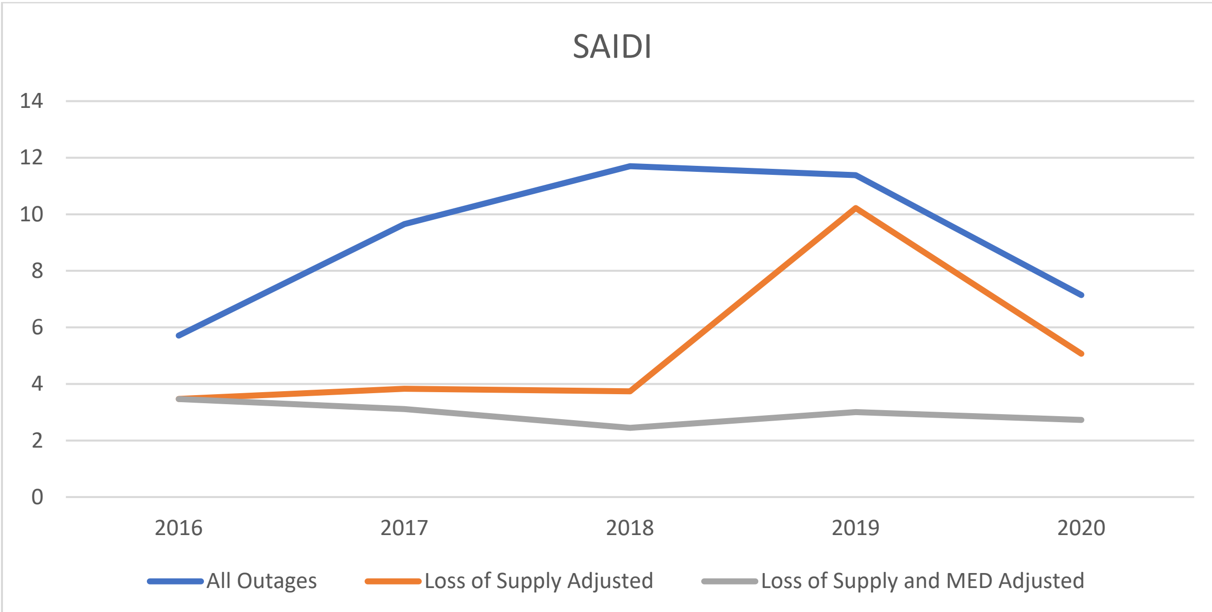
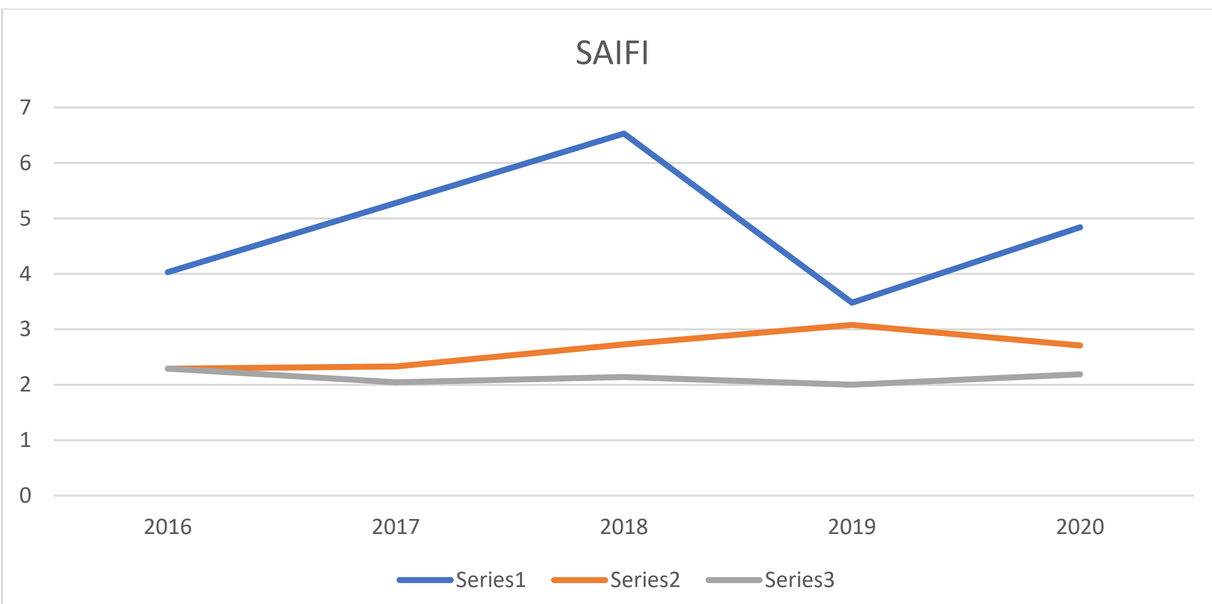


Figure 3: 2016-2020 SAIFI Trends



The figures above show that for outages within CNPI's control (i.e. loss of supply and MED Adjusted), outage duration and frequency are trending slightly downward over the most recent 5 years. From a customer perspective however, CNPI recognizes that total outage duration and frequency is trending upward, and that its customers experience the impacts of all system outages, regardless of the cause of the outage or whether the outage occurs during a major event. The balance of this section provides additional insight on system reliability during the historical period, including the impact of MED's and CNPI's efforts to address loss of supply and MED outages. The following Section 2.3.1.3.3 describes investments in the forecast period that are intended to further address CNPI's reliability challenges.

MAJOR EVENTS

CNPI experienced 6 MED's during the 2016-2020 period. The annual outage impacts resulting from these the events are summarized in Table 8.

Table 8: 2016-2020 Major Event Outage Impacts

System Reliability Indicators	2016	2017	2018	2019	2020
Customer Interruptions (Major Events)					
Unknown/Other	0	0	1,411	0	12
Scheduled Outage	0	0	2	0	0
Loss of Supply	0	0	0	0	16,917
Tree Contacts	0	8,232	2,507	4,939	2,129
Lightning	0	0	0	0	0
Defective Equipment	0	4	611	23	138
Adverse Weather	0	0	12,697	23,957	13,015
Adverse Environment	0	0	0	0	0
Human Element	0	0	0	2,970	0
Foreign Interference	0	0	0	0	0
Total	**0**	**8,236**	**17,228**	**31,889**	**32,211**
Customer-Hour Interruptions (Major Events)					
Unknown/Other	0	0	441	0	13
Scheduled Outage	0	0	4	0	0
Loss of Supply	0	0	0	0	23,900
Tree Contacts	0	20,958	6,423	18,680	15,594
Lightning	0	0	0	0	0
Defective Equipment	0	8	994	154	873
Adverse Weather	0	0	29,935	191,668	53,086
Adverse Environment	0	0	0	0	0
Human Element	0	0	0	1,799	0
Foreign Interference	0	0	0	0	0
Total	**0**	**20,966**	**37,797**	**212,301**	**93,466**

Table 9 below provides a high-level summary of the 6 MED's that occurred during the historical period.

Table 9: 2016-2020 Major Event Day Summary

Date	Weather	Storm Duration	% of Customers Affected	Time to Restore 90% of Affected Customers	Mutual Assistance
2017-10-15	Wind (70 km/h) Rain	15 hours	29%	4 hours	None
2018-04-04	Wind (96 km/h) Rain	20 hours	30%	8 hours	Contractor
2018-06-13	Wind (119 km/h) Thunderstorm	3.5 hours	30%	4 hours	Contractor
2019-02-24	Wind (105 km/h) Rain	14 hours	45%	11.5 hours	Contractor Other LDC
2019-10-31	Wind (130 km/h) Rain	20 hours	65%	40 hours	Contractor Other LDC
2020-11-15	Wind (130+ km/h) Rain	29 hours	72%	8.5 hours	Contractor Other LDC

The above summary of MED's shows an increasing frequency and intensity of severe storm events causing widespread outages and significant damage within CNPI's service area. In all cases, MED's were associated with significant wind storms, accompanied by rain. In many cases, additional rain leading up to the storm event resulted in saturated ground conditions, increasing the likelihood of otherwise healthy trees falling into CNPI's distribution lines. Ground saturation combined with intense winds off Lake Erie has also increasingly caused localized flooding and road closures during these major events, further complications CNPI's outage response.

As the number of customers experiencing outages and the overall extent of damage to CNPI's distribution system has continued to rise as a result of increasingly frequent and intense storms, CNPI has taken immediate steps to increase the amount of third-party assistance (i.e. independent contractors and neighbouring LDC's) deployed for outage restoration and repairs. CNPI has also increasing used its OMS system and various social media channels to improve communication with customers on relating to outage awareness, restoration updates and estimated restoration times during outage response.

As described in Section 2.1.2 CNPI has engaged with its customers through annual surveys, as well as through additional online surveys specific to this DSP. Section 4.1.3 provides details of how the results of this engagement have informed CNPI's future investment plans related to increasing system reliability.

LOSS OF SUPPLY EVENTS

2016-2020 reliability impacts from loss of supply outages are summarized in Table 10.

Table 10: 2016-2020 Loss of Supply Summary

Category	2016	2017	2018	2019	2020
Customer Interruptions					
Loss of Supply: Non-MED	50,042	85,614	111,074	11,680	46,474
Loss of Supply: MED	0	0	0	0	16,917
Loss of Supply: Total	**50,042**	**85,614**	**111,074**	**11,680**	**63,391**
SAIFI Contribution	1.74	2.95	3.80	0.40	2.13
Customer-Hour Interruptions					
Loss of Supply: Non-MED	64,792	168,833	232,912	34,034	37,505
Loss of Supply: MED	0	0	0	0	23,900
Loss of Supply: Total	**64,792**	**168,833**	**232,912**	**34,034**	**61,404**
SAIDI Contribution	2.24	5.82	7.96	1.16	2.07

CNPI observed an increasing trend in loss of supply outages between 2016 and 2018. During that period, CNPI worked extensively with Hydro One to develop solutions to improve supply reliability to both its Gananoque and Port Colborne service areas, as described in Section 2.2.1.3 above.

OUTAGE ANALYSIS 2016-2020 (EXCLUDING MED AND LOSS OF SUPPLY)

The following analysis provides the breakdown of historical outages for 2016-2020, by cause and normalized to exclude the MED and loss of supply outages discussed above. Tracking outage performance by cause code provides CNPI information on specific outage causes that need to be addressed should an undesired trend develop. Tables and figures supporting the following analysis are provided at the end of this section.

Tree Contact Outages: Excluding loss of supply events, tree contact outages are the leading cause of distribution system outages for CNPI. Customer interruptions and customer-hour interruptions are both trending slightly upward over the 2016-2020 period. In response to trends in tree contact outages, CNPI is gradually increasing its vegetation management efforts and continuing to monitor trends in outage statistics. CNPI also included a discussion of vegetation management efforts in its recent customer engagement surveys and found that customer support for increased vegetation management to improve reliability was notably lower than support for increased distribution system investments to improve reliability.

Defective Equipment Outages: Over the 2016-2020 period, this category has experienced the largest downward trend in both customer interruptions and customer-hour interruptions. CNPI continues to make significant capital investments in its distribution system to replace end of life assets and equipment at higher risk of failure, as described throughout this DSP.

Adverse Weather Outages: Outages caused by adverse weather vary considerably year-over year. Over the 2016-2020 period, both customer interruptions and customer-hour interruptions caused by adverse weather are trending upward. These trends are generally a result of storm damage on days that do not meet the MED criteria and CNPI expects that efforts to reduce the extent and duration of outages during major storms will have a positive impact on both MED outage statistics and non-MED outages classified as being caused by adverse weather.

Foreign Interference Outages: Over the 2016-2020 period, both customer interruptions and customer-hour interruptions caused by foreign interference are trending significantly upward. In an effort to reduce future outage impacts, CNPI began installing additional wildlife guards on certain equipment to reduce animal-caused outages.

All Other Causes: Over the 2016-2020 period, customer interruptions from all other causes (unknown/other, scheduled, lightning adverse environment and human element) are trending upward. This trend is caused by a spike in lightning-related customer interruptions in 2020, which were an order of magnitude higher than the 2016-2019 average. While the 2020 lightning caused outages affected a large number of customers, they were relatively short in duration, and despite customer interruptions trending upward, customer-hour interruptions are trending downward. CNPI continues to incorporate best practices for lighting protection when rebuilding distribution lines and substations.

Table 11: Customers Interrupted by Cause Code (2016-2020) – Excluding MED and Loss of Supply

Category	2016	2017	2018	2019	2020
Customer Interruptions					
Unknown/Other	13,418	5,656	5,666	365	3,268
Scheduled Outage	5,117	3,077	3,078	3,303	6,704
Tree Contacts	13,873	14,021	18,051	17,216	17,131
Lightning	985	2,957	130	14	10,630
Defective Equipment	28,843	11,178	12,994	11,516	9,131
Adverse Weather	847	11,820	13,319	9,108	2,954
Adverse Environment	35	107	618	613	1,294
Human Element	109	248	3,327	5,906	5,961
Foreign Interference	2,903	10,281	5,448	10,856	8,048
Total	**66,130**	**59,345**	**62,631**	**58,897**	**65,121**
Customer-Hour Interruptions					
Unknown/Other	2,587	12,495	13,992	3,506	544
Scheduled Outage	5,266	13,019	8,200	9,056	6,763
Tree Contacts	17,735	20,766	26,424	26,268	17,585
Lightning	2,036	2,013	5,198	607	102
Defective Equipment	11,877	43,263	8,365	11,322	23,323
Adverse Weather	20,636	976	11,227	15,688	17,642
Adverse Environment	2,603	94	83	290	1,076
Human Element	235	166	98	588	3,618
Foreign Interference	4,937	7,215	16,739	4,278	17,822
Total	**100,005**	**90,326**	**71,603**	**88,477**	**81,206**

Figure 4: Customer Interruptions by Cause Code (2016-2020) – Excluding MED and Loss of Supply

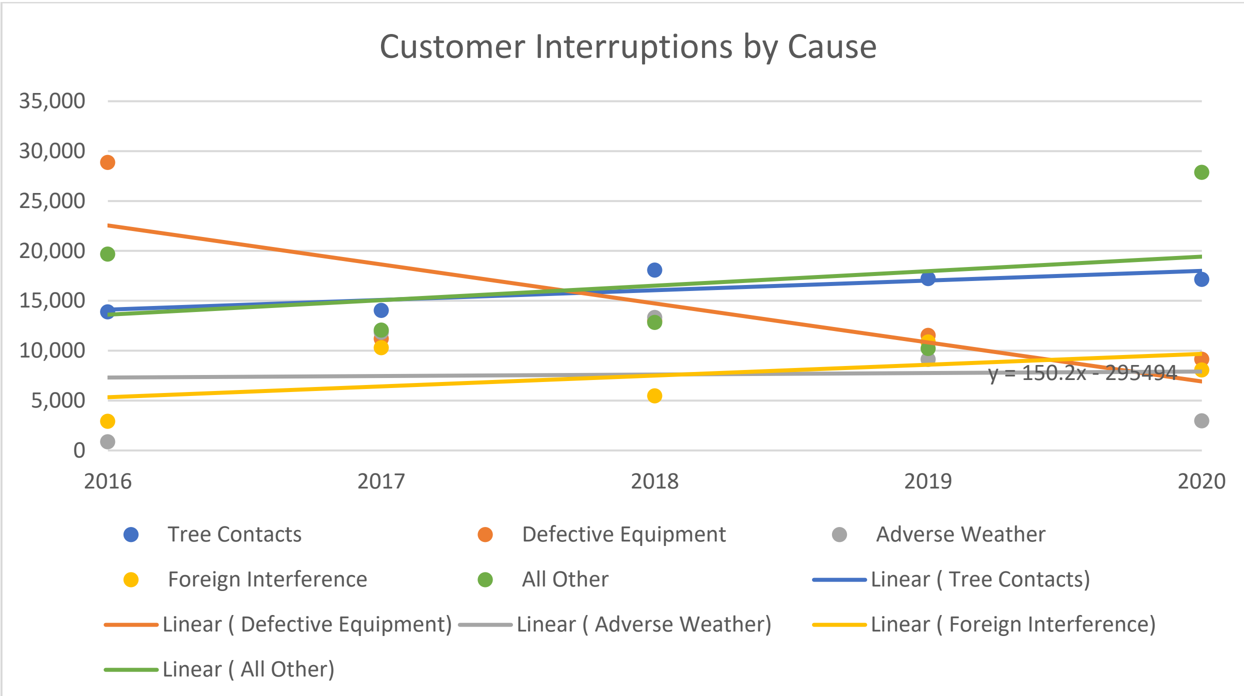
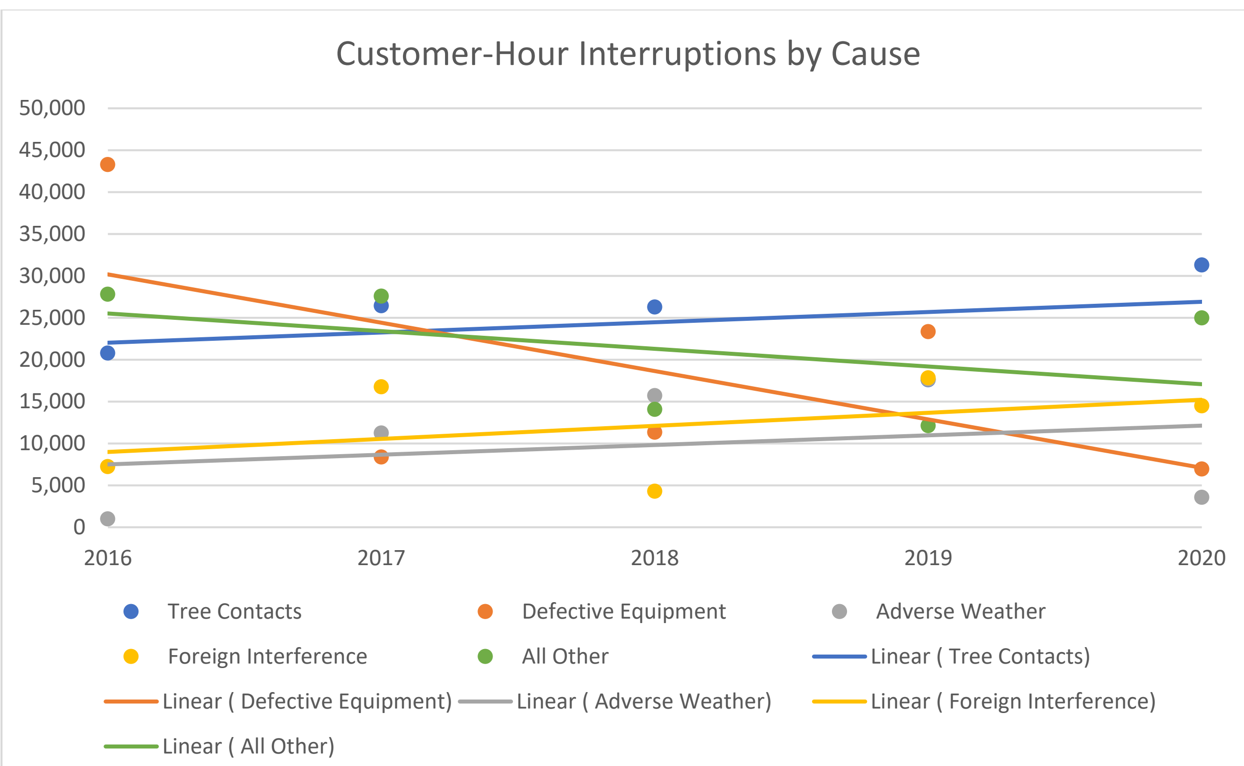


Figure 5: Customer-Hour Interruptions by Cause Code (2016-2020) – Excluding MED and Loss of Supply



2.3.1.3.3 PERFORMANCE TREND INTO THE DSP (5.2.3D)

Providing safe, reliable, and high-quality service to all customers in one of the key principles of CNPI's AMP. Further, CNPI's customers have consistently identified reliability among their top priorities through a number of customer engagement activities.

When normalized to exclude both MED's and loss of supply outages, both SAIDI and SAIFI are trending lower over the historical period. CNPI expects that its continued investments in asset replacements, voltage conversion programs and programs aimed at improving reliability will maintain the recent trend of gradual reliability improvements for outages within CNPI's control. Further, CNPI has coordinated extensively with Hydro One to address the circumstances which caused the most significant historical contributions to loss of supply outages and expects the recent reduction in loss of supply outages to continue into the forecast period.

CNPI will continue to focus on identifying alternatives to reduce the impact of MED outages in order to address the increasing trend of severe storm damage. Alternatives such as increased vegetation management, storm hardening, distribution automation and improved contingency options will be considered as potential solutions in the most affected areas of CNPI's system, with consideration of cost/benefit tradeoffs and input from customer engagement. Section 4.2 of this DSP provides additional detail on how these alternatives are considered in the context of CNPI's overall capital planning process.

2.3.2 COST EFFICIENCY AND EFFECTIVENESS

2.3.2.1 COST CONTROL

In this section, CNPI discusses the cost measures from Appendix 5-A of the Filing Requirements as well as total cost benchmarking and efficiency assessments from its OEB scorecard. CNPI has also filed the OEB Appendix 5-A workbook and the OEB Benchmarking Forecast Model in live Excel format along with its Application.

The Appendix 5-A measures are calculated based on CNPI's total annual capital and O&M costs, divided by customer counts, peak load and line km[7] to determine unit costs. Inputs to these calculations are consistent with CNPI's RRR filings and the OEB's Yearbooks of Electricity Distributors, as well as the values presented elsewhere in this Application.[8]

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[7] In accordance with the OEB's March 31, 2020 letter related to RRR amendments for the 2019 fiscal year, CNPI started reporting secondary line km in 2019. CNPI notes that the OEB's 2019 yearbook and scorecard unit cost calculations have incorporated total line km as filed in RRR 2.1.5 (i.e. primary + secondary line km), and anticipates that future OEB publications will be consistent with 2019. CNPI has therefore adjusted the per km cost measures for 2017 and 2018 in this DSP to include secondary km, in order to provide comparable year-over-year analysis.
[8] 2021 values are determined on a forecast basis, using the Bridge Year cost forecasts presented in this DSP, assuming 2021 peak load and line km equal to 2020 values, and increasing 2020 year-end customer counts by the growth factors contained in CNPI's load forecast.

In contrast to the OEB Appendix 5-A measures, cost efficiency measures appearing on CNPI's OEB Scorecard and in the PEG cost benchmarking analysis include certain adjustments that attempt to make the results more comparable between distributors. Therefore, these amounts will not necessarily reconcile to the amounts presented in Exhibits 1 through 9 of the Application. For example, the PEG cost benchmarking model and related OEB Scorecard reporting:

- excludes certain OM&A accounts;
- calculates "actual" capital costs based on assumptions of capital stock and a capital price;
- assumes that all LDC's have the same embedded weighted average cost of capital, depreciation rates and construction costs for the purpose of calculating "actual" capital costs.

2.3.2.1.1 METHODS AND MEASURES (5.2.3B)

For each historical year of the historical period, CNPI has calculated the OEB Appendix 5-A cost metrics based on the following formulas:

$$Total\ Cost\ per\ Customer\ = \frac{\sum Capital\ Additions\ \&\ O\&M\ Costs}{Number\ of\ customer\ served}$$

$$Total\ Cost\ per\ Kilometer\ of\ Line\ = \frac{\sum Capital\ Additions\ \&\ O\&M\ Costs}{Kilometers\ of\ line}$$

$$Total\ Cost\ per\ MW\ = \frac{\sum Capital\ Additions\ \&\ O\&M\ Costs}{Annual\ Peak\ Load\ (MW)}$$

$$Total\ CAPEX\ per\ Customer\ = \frac{\sum Capital\ Additions}{Number\ of\ customer\ served}$$

$$Total\ CAPEX\ per\ Kilometer\ of\ Line\ = \frac{\sum Capital\ Additions}{Kilometers\ of\ line}$$

$$O\&M\ Cost\ per\ Customer\ = \frac{\sum O\&M\ Costs}{Number\ of\ customer\ served}$$

$$O\&M\ Cost\ per\ Kilometer\ of\ Line\ = \frac{\sum O\&M\ Costs}{Kilometers\ of\ line}$$

The "1 Year" values included in the OEB Appendix 5-A Excel file reflect 2021 calculations, while the "5 Year Average" values are the average of the 2017 to 2021 results (forecast for 2021) for each metric.

Total costs in the OEB Scorecard metrics reflect CNPI's total OM&A costs, with adjustments to exclude certain accounts, and a calculated capital cost component based on assumptions of capital stock and price inputs. Once those "actual" total costs are calculated within the total cost benchmarking models used by the OEB, the results are divided by number of customers and line km for Scorecard reporting.

The efficiency assessment on the OEB Scorecard reflects grouping based on the ratio of calculated actual to predicted costs for each LDC in the total cost benchmarking model, according to the following table.

Table 12: Cost Benchmarking Efficiency Groups

Efficiency Group	Cost Performance
1	Actual costs are 25% or more below predicted costs
2	Actual costs are 10% to 25% below predicted costs
3	Actual costs are within +/- 10% of predicted costs
4	Actual costs are 10% to 25% above predicted costs
5	Actual costs are 25% or more above predicted costs

2.3.2.1.2 HISTORICAL PERFORMANCE (5.2.3C)

Summary

The following tables summarize the OEB Appendix 5-A and OEB Scorecard cost efficiency measures over the historical period.

Table 13: OEB Appendix 5-A Metrics 2017-2021

Metric	2017	2018	2019	2020	2021
Total Cost per Customer	496	662	659	679	699
Total Cost per km of Line	9,106	12,135	12,124	12,970	13,420
Total Cost per MW	162,255	197,434	208,877	198,176	205,044
Total CAPEX per Customer	361	526	524	537	560
Total CAPEX per km of Line	6,626	9,648	9,640	10,259	10,753
Total O&M per Customer	135	136	135	142	139
Total O&M per km of Line	2,480	2,487	2,484	2,711	2,667

Table 14: OEB Scorecard Metrics 2017-2021

Cost Efficiency Benchmarking	2017	2018	2019	2020	2021
Efficiency Assessment	4	4	4	4	4
Total Cost per Customer	773	867	893	907	947
Total Cost per km of Line	21,875	24,425	16,421	17,328	18,183
Cost/km Adjusted to Include Secondary	14,186	15,899	16,421	17,328	18,183

OEB Appendix 5-A Total Cost Metrics

CNPI's total cost per customer and total cost per km of line metrics increased by 33% from 2017 to 2018 as a result of 2017 actual capital investments coming in below planned levels and an increase in capital investments in 2018. 2018-2021 results were relatively flat. The total cost per MW metric follows a slightly different trend than other total cost metrics due to greater variability in annual peak load as compared to line km and customer counts. Over the entire 2017-2021 historical period the compound annual growth rate for CNPI's total cost metrics ranged between 4.8 to 8.1%. 2017-2021 trending for CNPI's total cost metrics is illustrated in the figures below.

Figure 6: Performance Measure – Total Cost per Customer

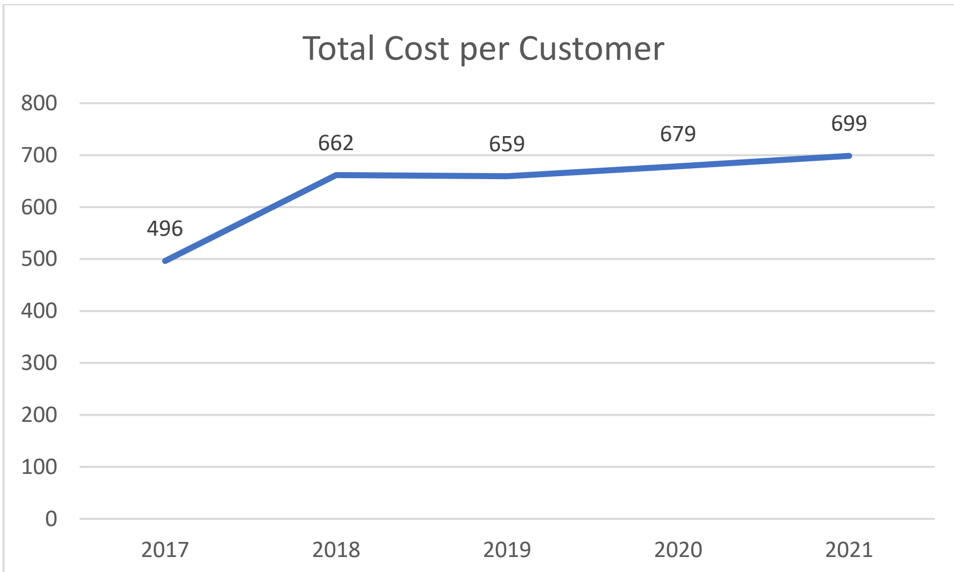


Figure 7: Performance Measure – Total Cost per Kilometer of Line

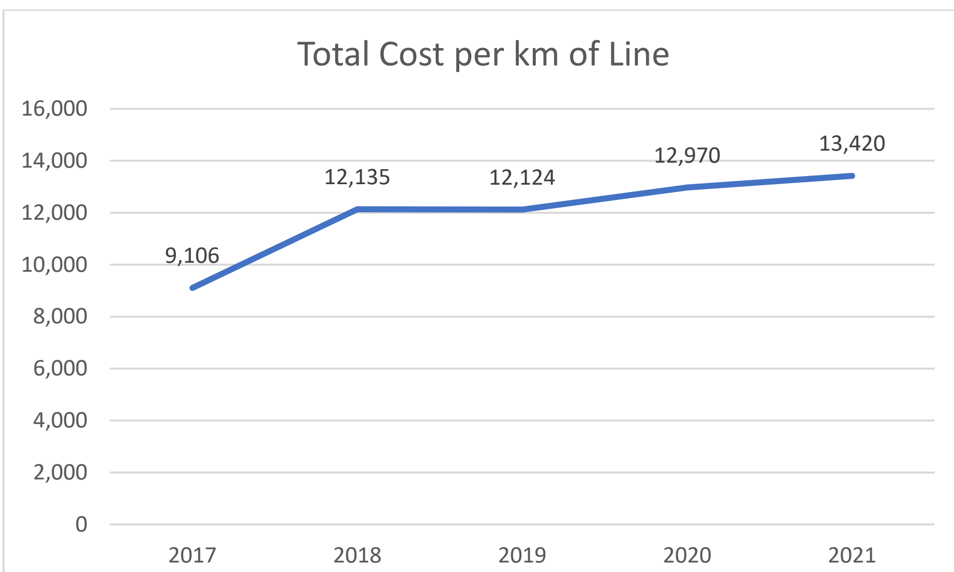
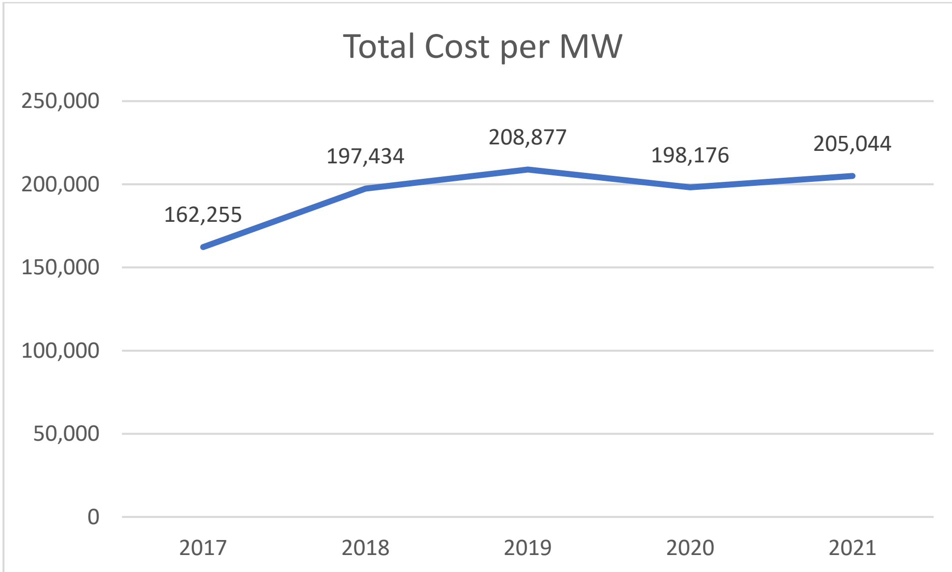


Figure 8: Performance Measure – Total Cost per MW



OEB Appendix 5-A CAPEX Metrics

CNPI's capex per customer and capex per km of line metrics followed the same trend as the total cost metrics described above (i.e. 2017-2018 increases, followed by 2018-2021 trends that were relatively flat). Over the entire 2017-2021 historical period the compound annual growth rate for CNPI's capex metrics was 9.2% on a per customer basis and 10.2% on a per km of line basis. 2017-2021 trending for CNPI's capex metrics is illustrated in the figures below.

Figure 9: Performance Measure – CAPEX per Customer

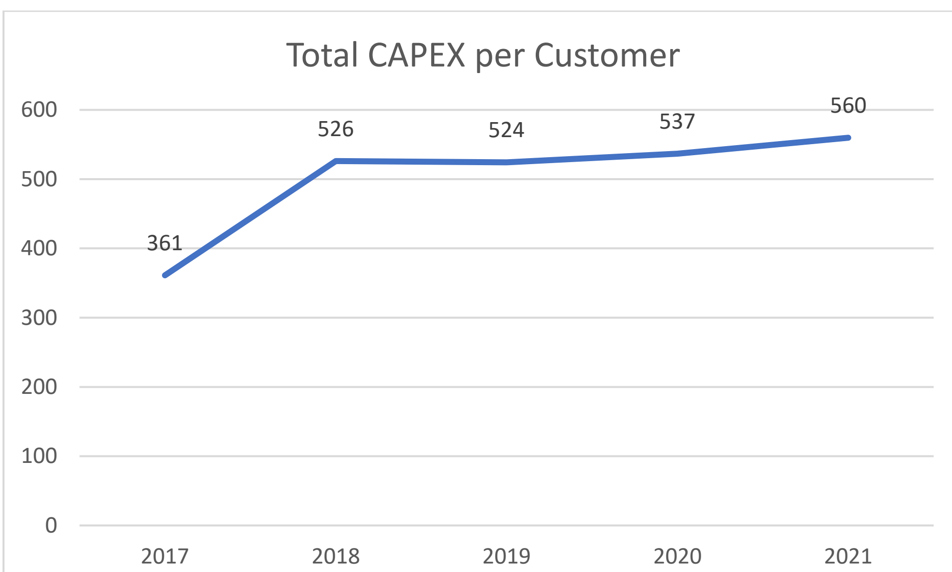
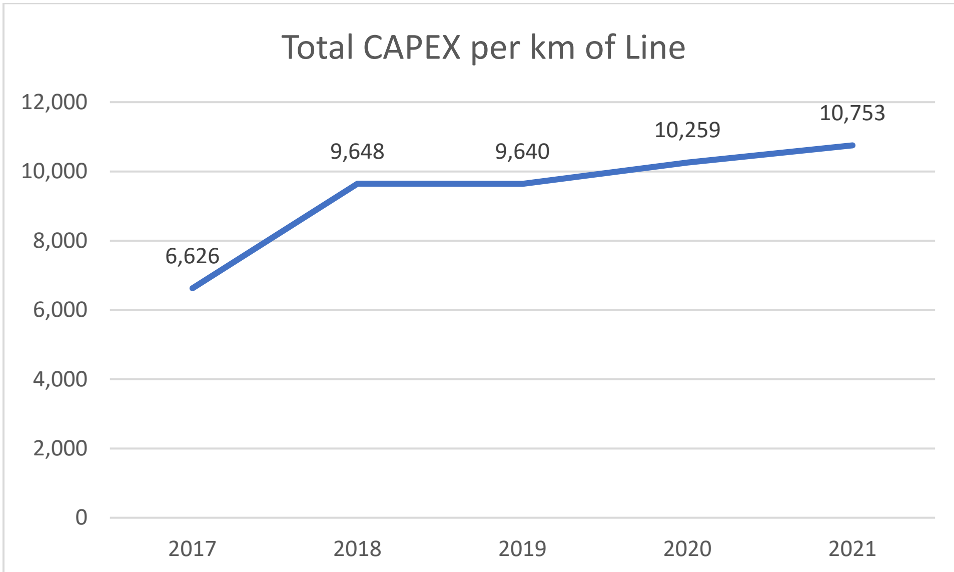


Figure 10: Performance Measure – CAPEX per km of Line



OEB Appendix 5-A O&M Metrics

CNPI's O&M per customer metric was essentially flat from 2017-2019, followed by a 5% increase from 2019 to 2020 and a 2.1% decrease from 2020 to 2021. Overall inflationary increases in O&M costs are essentially being offset by a small amount of customer growth. O&M per km of line costs experienced a larger increase from 2019 to 2020 due to reductions in CNPI's reported secondary line km resulting from updated GIS queries. 2017-2021 trending for CNPI's O&M metrics is illustrated in the figures below.

Figure 11: Performance Measure – O&M per Customer

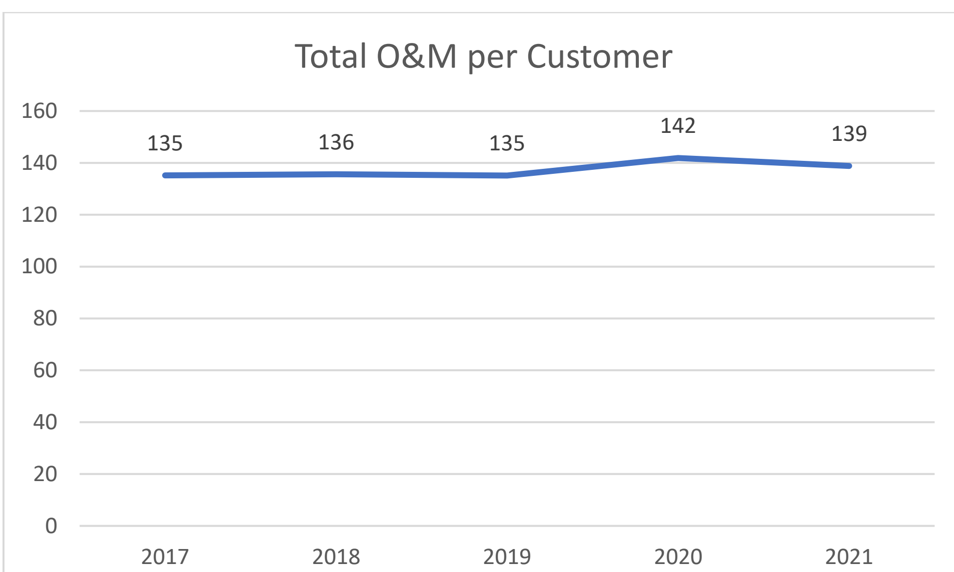
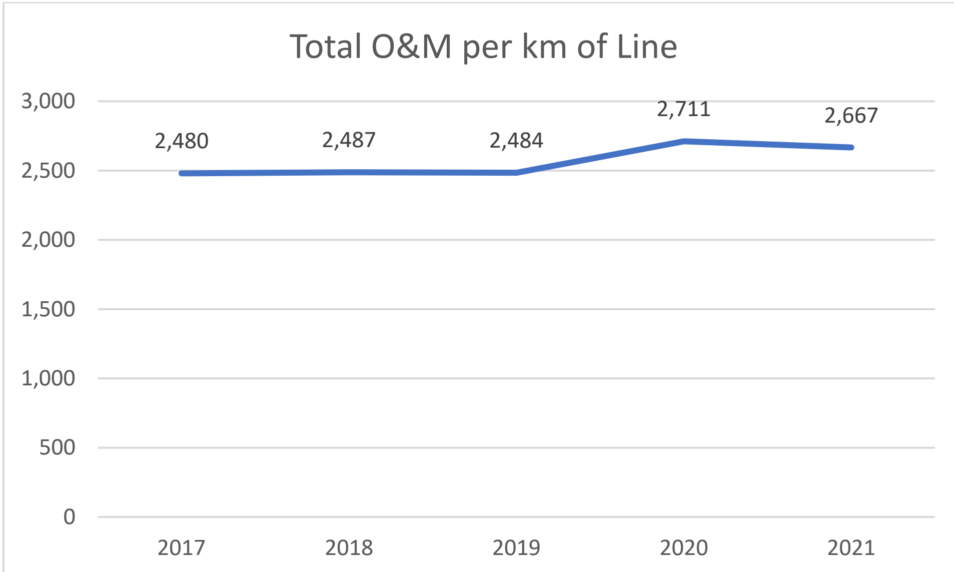


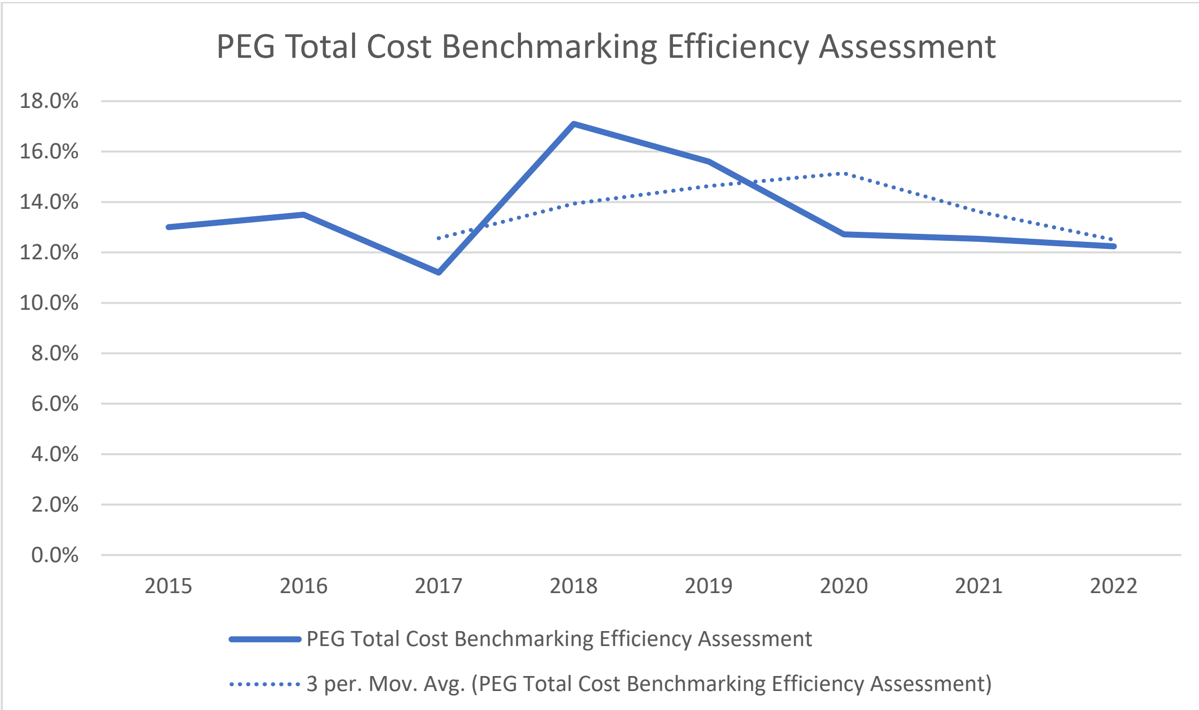
Figure 12: Performance Measure – O&M per km of Line



OEB Total Cost Benchmarking Efficiency Trending

Figure 13 below illustrates the percentage difference between CNPI's "actual" total costs and its predicted total costs, as calculated by the OEB's Total Cost Benchmarking Model. Because the benchmarking results can vary significantly year-over-year, the efficiency groupings are based on a 3-year rolling average, which is also shown in Figure 13. The trend shows CNPI's performance decreasing over the 2017-2020 period as CNPI increased capital investments in its distribution system, with a forecasted improving trend from 2020 to 2022, primarily resulting from a decreasing trend in capital investments and modest customer growth, which increases predicted costs in the benchmarking model.

Figure 13: PEG Total Cost Benchmarking Efficiency Assessment



2.3.2.1.3 PERFORMANCE TREND INTO THE DSP (5.2.3D)

As described in Sections 3 and 4 of this DSP, CNPI strives to provide safe, reliable and high-quality service to its customers through comprehensive asset management and system planning processes. During the historical period, CNPI increased its capital investment levels as compared to the plan presented in its previous DSP, in response to a significant increase in customer connection requests as well as ongoing reliability and safety concerns associated with its legacy delta-connected distribution systems.

After accelerating capital investments through the historical period, the plan presented in this 2022-2026 DSP includes capital investment forecasts that are less than 2017-2021 average levels and O&M costs controlled to inflationary levels. As a result, CNPI expects downward pressure on the various cost efficiency metrics described above over the 2022-2026 period. The specific trends are likely to vary by individual metric, based on the nature of costs included in each metric as well as changes to customer counts, annual peak load, and total line km.

2.3.3 ASSET/SYSTEM OPERATIONS PERFORMANCE

2.3.3.1 SAFETY

CNPI expects its employees and contractors working on its behalf to demonstrate a personal, unrelenting commitment to safety and environmental excellence as a core value. CNPI provides necessary training, equipment and procedural support for its employees to maintain safety as a priority. Any incidents or accidents that do occur are reported, reviewed and effectively communicated within the organization, with a goal of improving processes and procedures to prevent future incidents. This communication occurs through a variety of safety alerts and safety meetings, with additional training and review of procedures introduced as required.

2.3.3.1.1 METHODS AND MEASURES (5.2.3A)

ESA annually reports a number of safety-related metrics to the OEB for inclusion on LDC scorecards. The safety measures reported by ESA include:

- Public Awareness of Electrical Safety
- Compliance with Ontario Regulation 22/04
- Serious Electrical Incident Index

2.3.3.1.2 HISTORICAL PERFORMANCE (5.2.3C)

CNPI was compliant with Ontario Regulation 22/04, as confirmed through annual audits during the historical period. One serious electrical incident was included on CNPI's 2019 scorecard. This incident involved a mast of a sailboat coming into contact with a power line while being removed from a boat launch. CNPI's power line had clearances exceeding required standards, but the boat mast was not lowered between the boat ramp and a nearby storage facility. There was damage caused to the mast of the sailboat, but no injuries were associated with this incident. CNPI worked with the marina to permanently raise the overhead crossing to provide additional clearance and to install additional warning signage.

CNPI will continue to bring public awareness of the safety risks its assets present to customers, how to avoid incidents, and how to appropriately respond should an incident occur through public education programs such as First Responders presentation, social media communications, and public safety surveys. In 2019, UtilityPulse was engaged to complete surveys in relation to the Public Awareness of Electrical Safety scorecard measure. Province-wide scores ranged from 80% to 85%, with both average and median index scores of 83%. CNPI's score of 83% suggest that members of the public are generally well-informed about the safety hazards associated with electrical distribution systems, but also that further education and continued engagement would be beneficial.

Table 15: Performance Measures - Safety

Safety Measures	2016	2017	2018	2019	2020
Level of Public Awareness	81%	81%	81%	83%	83%
Level of Compliance with Reg. 22/04	Compliant	Compliant	Compliant	Compliant	Compliant
Number of Serious Electrical Incidents	0	0	0	1	0
Serious Incident Rate per 1000 km of Line	0	0	0	0.963	0

2.3.3.1.3 PERFORMANCE TREND INTO THE DSP (5.2.3D)

Continuous improvement is a key aspect of CNPI's corporate safety policy. As such, CNPI will continue to undertake efforts related to customer education, communication, and community engagement, with a goal of continuously improving its Level of Public Awareness score, as measured by third-party surveys. CNPI will continue to maintain focus on health and safety as a core value and strives to remain fully compliant with Ontario Regulation 22/04, as determined through annual compliance audits. Notwithstanding that the OEB Scorecard calculates a serious electrical incident rate target based on a 5-year average of past performance, CNPI will always set a target of zero high-risk incidents.

2.3.3.2 SYSTEM LOSSES

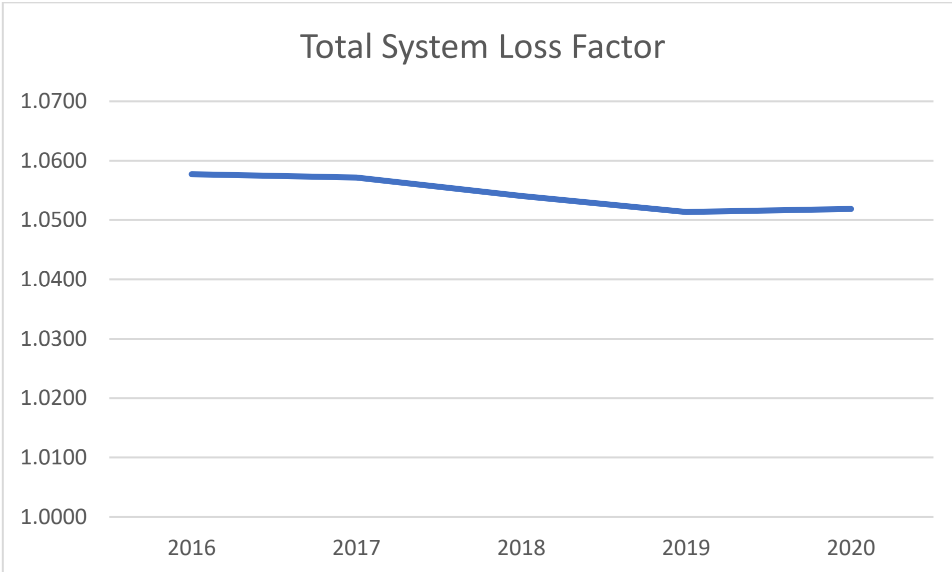
2.3.3.2.1 METHODS AND MEASURES (5.2.3A)

Through its annual RRR filing CNPI reports on total energy supplied to its distribution system, and total energy delivered to its customers, allowing a calculation of total system losses. CNPI manages system design and operation to decrease system loss, as defined in the *OEB Practices Relating to Management of System Losses*.

2.3.3.2.2 HISTORICAL PERFORMANCE (5.2.3C)

CNPI's trend in total system loss factor is illustrated in Figure 14. The system loss factor was at its recent highest level in 2016 and 2017. During these years, CNPI was in the midst of major substation voltage conversion projects in both Fort Erie and Gananoque prior to undertaking extensive distribution line voltage conversion work. During the substation rebuilds, load normally supplied existing delta-connected load would have been switched to a smaller number of stations/transformers/feeders than normal, increasing load losses. As voltage conversion program has progressed over the historical period, CNPI's system loss factor has gradually decreased.

Figure 14: Performance Measure - System Losses



2.3.3.2.3 PERFORMANCE TREND INTO THE DSP (5.2.3D)

CNPI will continue to include line loss evaluation in its assessment of various project alternatives to address identified needs. Ongoing voltage conversion programs, system upgrades to improve contingency response, and end of life asset replacements are expected to result in downward pressure on distribution system losses. At the same time, annual variations in system load related to weather and customer changes could result in annual variability in CNPI's system losses.

2.4 REALIZED EFFICIENCIES DUE TO SMART METERS (5.2.4)

CNPI's 2017 cost of service application incorporated all capital costs and ongoing O&M costs associated with full deployment of smart meters and MIST meters, and full transition to automated metering for all customer classes (with limited exceptions for troubleshooting or due to communication issues).

CNPI continues to explore opportunities to use smart meter data to improve operational and customer service processes. For example, significant progress has been made towards incorporating "last-gasp" technology into CNPI's Outage Management System to improve outage response as well as customer communications during outages.

3 ASSET MANAGEMENT PROCESS (5.3)

CNPI has included a copy of its Asset Management Program ("AMP") as Appendix A. This section of the DSP provides an overview of CNPI's asset management process, an overview of the assets managed by CNPI, and a summary of CNPI's asset lifecycle optimization policies and practices. The information is presented in accordance with Section 5.3.1 of the OEB's Chapter 5 Filing Requirements, and describes how CNPI's AMP interacts with other inputs to arrive at the capital investment plan outlined in Section 4 of this DSP.

3.1 ASSET MANAGEMENT PROCESS OVERVIEW (5.3.1)

CNPI's AMP is founded on objectives and principles that link the OEB's four identified categories of RRFE performance outcomes with CNPI's organizational core values. The asset management process leverages asset records and condition information, as well as additional analysis and studies completed by CNPI staff or third parties, to determine the pacing and prioritization of future capital and O&M programs and projects.

3.1.1 ASSET MANAGEMENT OBJECTIVES (5.3.1A)

The fundamental objective of CNPI's AMP is to prudently and efficiently manage the planning and engineering, design, addition, inspection and maintenance, replacement, and retirement of all distribution assets in a sustainable manner that maximizes safety and customer reliability, while optimizing asset lifecycle costs.

This objective is met through the application of thorough and sound planning, prudent and justified budgeting, and ongoing oversight, documentation, and review of all efforts and expenditures while implementing the documented capital and operating plans.

The relationship between CNPI's asset management objectives and the objectives of its overall system planning and capital expenditure planning processes is described in Section 4.2.1.

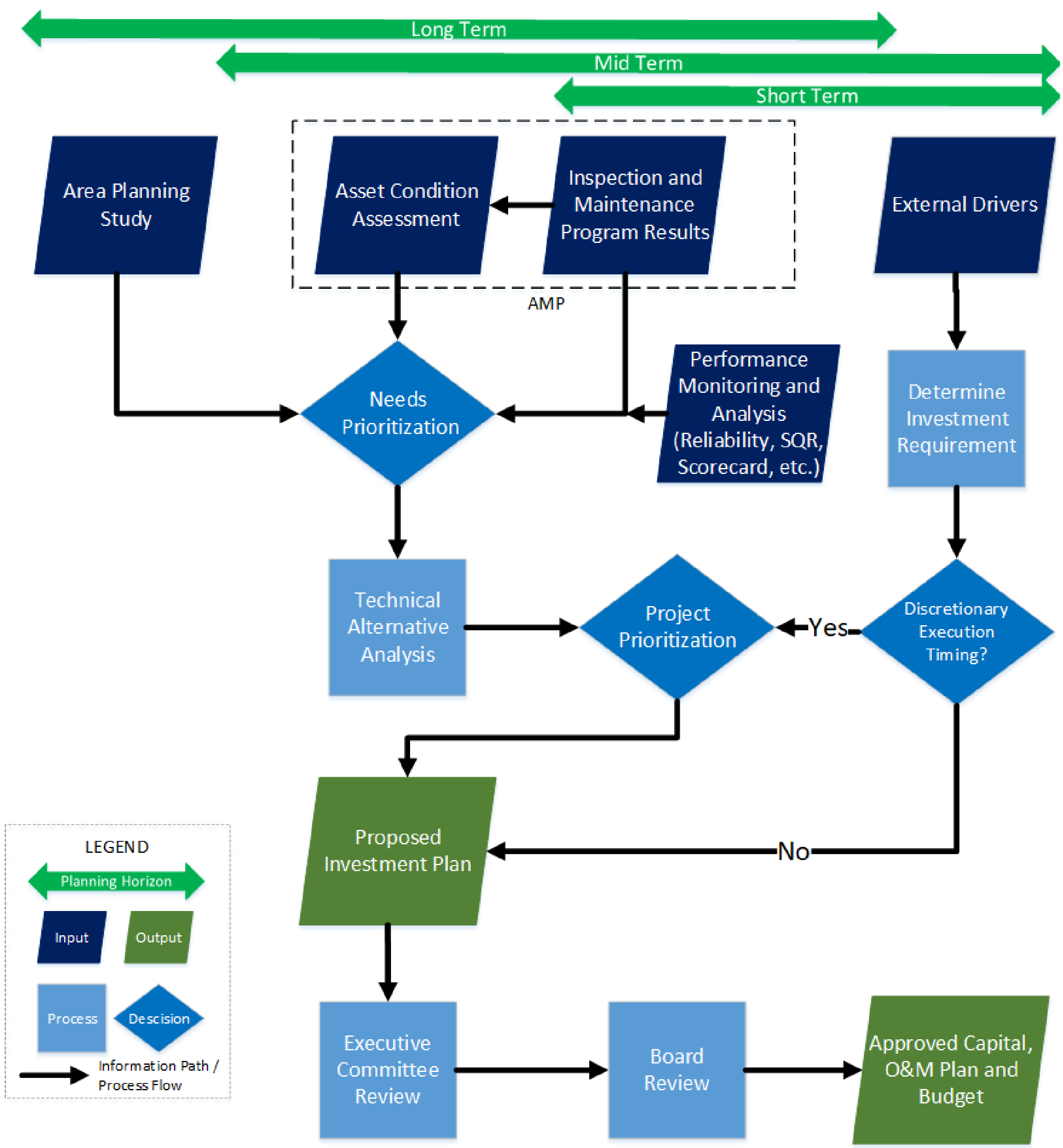
3.1.2 COMPONENTS OF THE ASSET MANAGEMENT PROCESS (5.3.1B)

Since filing its 2017-2021 DSP, CNPI has revised the format of its AMP to focus on items related to identification and management of its distribution system assets. Other distribution system planning activities such as area planning studies, reliability analysis and monitoring of performance outcomes are now addressed directly in this DSP and appendices to the DSP, rather than in the stand-alone AMP document.

The balance of this section describes the various components of CNPI's AMP, as well as how the AMP relates to other inputs and components of CNPI's overall distribution system planning process, as illustrated in Figure 15 below.

Certain inputs listed in Section 5.3.1(b) of the Filing Requirements, such as asset capacity utilization/constraint, and reliability-based inputs, are discussed in Section 4.2 in the context of CNPI's overall distribution system planning and capital expenditure planning processes.

Figure 15: System Planning Process



As discussed above, CNPI's AMP focuses on items related to identification and management of its distribution system assets. The two main interactions between the AMP and CNPI's overall system planning process are the Asset Condition Assessment ("ACA") and Inspection and Maintenance Programs, as described below.

Asset Condition Assessment

Since its previous DSP, CNPI has worked with an independent third-party expert, METSCO Energy Solutions, to formalize the ACA portion of the above flow chart. Key inputs to the ACA process include CNPI's asset registry information as well as any available inspection and maintenance reports, test results or other information that would support an assessment of the condition of CNPI's assets. This information was provided to METSCO at the outset of the ACA process, and clarified as required during the development of the ACA report. Section 3.2.3 below provides a summary of the ACA results and the complete ACA report is included as Appendix D.

Inspection and Maintenance Program Results

The ACA prepared to support this DSP provides a point-in-time summary of the condition of CNPI's assets. CNPI's regular inspection and maintenance programs, with intervals ranging from monthly to multi-year, will undoubtedly discover changes in asset condition over time. Further, for asset classes containing higher volumes of assets (e.g. poles), the ACA is meant to provide a representative health index for the entire class of assets to inform overall replacement requirements, with an expectation that ongoing inspection and maintenance results (e.g. specific results from multi-year pole testing and feeder inspection programs) will inform the actual priority for asset replacements on an annual basis.

Inspection and maintenance program results will also inform future updates to the ACA, improving the data availability indices for certain asset classes.

3.2 OVERVIEW OF ASSETS MANAGED (5.3.2)

The following sections provide broad descriptions of CNPI's service area and its distribution system configurations, followed by detailed descriptions of the number, type and condition of various distribution system assets and as assessment of CNPI's current system utilization.

3.2.1 DESCRIPTION OF THE SERVICE AREA (5.3.2A)

CNPI's service areas primarily include the Town of Fort Erie, the City of Port Colborne, and the Town of Gananoque.[9]

[9] Certain specific addresses near municipal boundaries are served by other distributors and therefore excluded from CNPI's licensed service area. Similarly, CNPI serves a small number of addresses outside of these municipal boundaries.

CNPI serves approximately 26,200 customers in Port Colborne and Fort Erie. CNPI serves an additional approximately 3,600 customers in the portion of its service area in and around Gananoque, operating as Eastern Ontario Power in the Gananoque area.

CNPI's combined service areas cover 357 square kilometres, approximately 80% of which is rural. CNPI's distribution system is comprised of over 1,600 km of primarily overhead distribution lines, and supplies a combined summer-peaking demand of approximately 100 MW.

Each of the three former LDCs that now comprise CNPI (CNPI, Port Colborne Hydro and Granite Power Corporation) were independently owned and operated for decades prior to operation and ownership changes involving CNPI in the 2001-2011 period. As a result, through a series of different planning decisions, operating philosophies, and construction standards, the three systems have distinct supply points and different primary system voltages, requiring separate system planning studies to be completed for each area.

The climate in CNPI's service area is humid continental, which is characterized by large variations in seasonal temperatures including cold winters and warm, humid summers. The location of CNPI's service areas along the shores of Lake Erie and Lake Ontario often results in lake-effect winds and precipitation more severe than areas further inland, which presents a significant challenge with respect to reliability improvement.

Major industries in CNPI's service area include refining/manufacturing/fabricating (industrial, metals, chemical and food products, among others), tourism/service/hospitality, agriculture, as well as other supporting industries. Over the past 10 years, CNPI's service area has seen a gradual decline in commercial and industrial load (particularly for larger customers), partially offset by a gradual increase in residential customers and associated load.

3.2.2 SUMMARY OF SYSTEM CONFIGURATION (5.3.2B)

CNPI's distribution systems in the Niagara area are primarily supplied by eleven 34.5 kV feeders from two transmission stations in Fort Erie (Station 17 and Station 18 owned by CNPI Transmission) and by four 27.6 kV feeders from Hydro One's Port Colborne TS.[10] These 34.5 kV and 27.6 kV feeders serve a dual purpose of supplying some areas and large customers directly, while also supplying a number of distribution substations that in turn supply lower voltage feeders as summarized below.

CNPI's distribution system in the Gananoque area is embedded within Hydro One's 44 kV subtransmission system. The Main substation steps down the 44 kV supply to three 27.6 kV feeders, which serve a dual purpose similar to the Port Colborne 27.6 kV system described above.

[10] An immaterial portion of CNPI's Port Colborne load can alternatively be supplied from a 27.6 kV delivery point embedded on a Hydro One feeder supplied by Crowland TS.

Table 16 provides a summary of CNPI's total primary distribution line distance by voltage level, overhead vs. underground construction, and by number of phases.

Table 16: Line km Summary

Voltage Level	km	Overhead vs. Underground	km	# of Phases	km
< 5 kV	423	Overhead	935	1 Phase	388
5-15 kV	193	Underground	100	2 Phase	60
27.6 -44 kV	420			3 Phase	588
Total	1,036	Total	1,036	Total	1,036

Section 2 of CNPI's AMP provides detailed descriptions of its distributions in each of its service areas, including service area and system maps, voltage levels in use, substations, capacity and a number of additional considerations. The following tables, reproduced from the AMP, summarize the configuration and capacity of substations owned by CNPI, and the number of feeders supplied from each substation. Total capacity values listed in these tables represent the sum of the highest nameplate rating (i.e. the fan-cooled rating where applicable) of all transformers unless otherwise noted.

Table 17: Fort Erie Distribution Substations

Station	Secondary Voltage	# of Transformers	Transformer Age	Total Capacity (MVA)	# of Feeders
Station 12	4.8 kV Delta	3	1963, 1977, 2001	23.5	12
Station 19	4.8/8.3 kV Wye	2	1999 (2)	26.6	6
Gilmore	4.8/8.3 kV Wye	2	2014, 2016	20	4
Rosehill[11]	4.8/8.3 kV Wye	2	2020 (2)	20	6

Table 18: Port Colborne Distribution Substations[12]

Station	East or West of Welland Canal	# of Transformers	Transformer Age	Total Capacity (MVA)	# of Feeders
Jefferson	West	1	2018	5	3
Catharine	West	1	1977	6.7	4
Fielden	West	2	2014, 2019	15.2	7
Killaly	East	2	1979[13]	9	4
Beach/ Sherkston	East	2	1959, 2009	10[14]	4

[11] Rosehill DS construction initiated in 2020, to be completed in 2021.
[12] All feeders supplied from Port Colborne distribution substations operate at 2.4/4.16 kV
[13] These transformers were refurbished in 2003 and 2006.
[14] One of the two transformers (T2 – 2009 vintage) is rated 10 MVA and supplies all load. T1 (1959 vintage) rated 5 MVA serves as an energized backup unit only.

Table 19: Gananoque Distribution Substations

Station	Voltage	# of Transformers	Transformer Age	Total Capacity (MVA)	# of Feeders
Main DS	44-27.6 kV	2	2006, 2017	66	3
Herbert DS	27.6-4.16 kV	1	1992	6	3
Gananoque DS	27.6-4.16 kV	2	1956, 1995	10	6

3.2.3 RESULTS OF ASSET CONDITION ASSESSMENT (5.3.2C)

CNPI's 2020 Asset Condition Assessment Report (the "ACA Report") is provided as Appendix D. The ACA Report was initiated in mid-2020, based on the most recent asset registry information, inspection and maintenance records and test results available at that time, as discussed in Section 2.1.5 of this DSP.

The following table and figures summarize the quantity, condition and data availability for each asset class included in the ACA Report. The ACA Report also contains age profiles by asset class, and discusses the factors that contributed to the determination of the overall health index for each asset class.

Table 20: Summary of ACA Results

Asset Class	Population	Health Index Distribution (Rounded %)						Average Health Index	Average DAI
		Very Good	Good	Fair	Poor	Very Poor	No HI		
Distribution Assets									
Wood Pole	23466	32.1%	15.7%	18.5%	33.4%	0.4%	0.0%	73.2%	21.0%
Pole-Mount Transformer	3795	15.2%	12.6%	30.5%	18.7%	13.0%	9.9%	51.2%	90.1%
Pad-Mount Transformer	648	21.8%	26.7%	34.7%	7.3%	0.9%	8.6%	64.1%	91.4%
Ratio Bank	53	35.9%	0.0%	49.1%	0.0%	13.2%	1.9%	62.5%	98.1%
Reclosers	35	37.1%	42.9%	5.7%	0.0%	11.4%	2.9%	77.2%	97.1%
Station Assets									
Power Transformer	24	4.2%	50.0%	33.3%	8.3%	4.2%	0.0%	70.0%	97.0%
Circuit Breaker	64	93.8%	4.7%	1.6%	0.0%	0.0%	0.0%	98.5%	43.0%
Protection Relay	29	93.1%	6.9%	0.0%	0.0%	0.0%	0.0%	96.1%	100.0%
Batteries	12	66.7%	16.7%	16.7%	0.0%	0.0%	0.0%	88.6%	89.0%
Grounding Grid	14	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	100.0%

Figure 16: Summary of Health Index Results for Distribution Line Assets

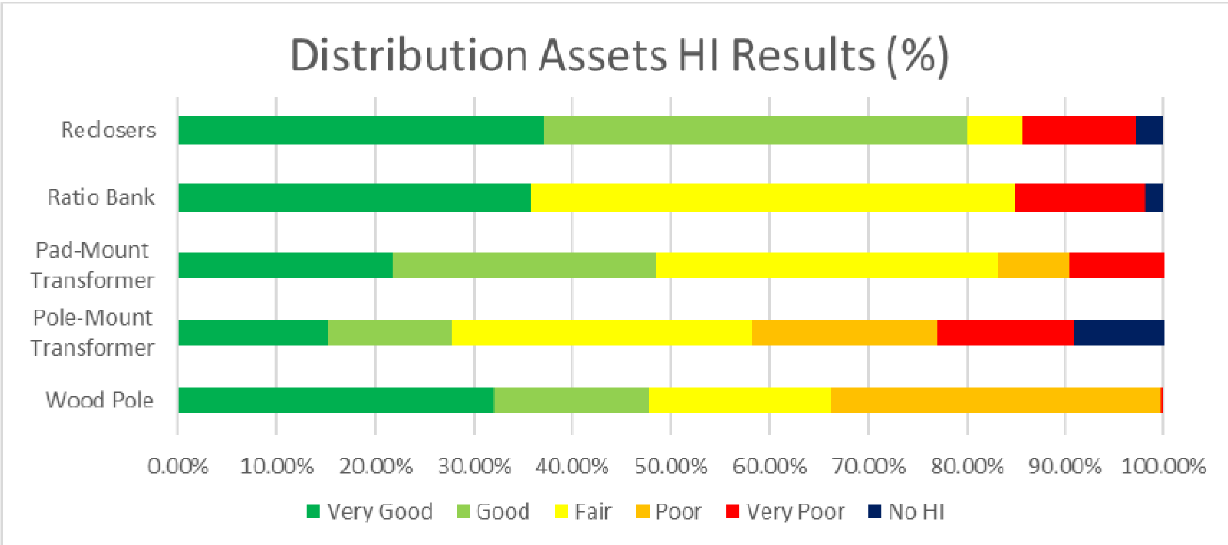
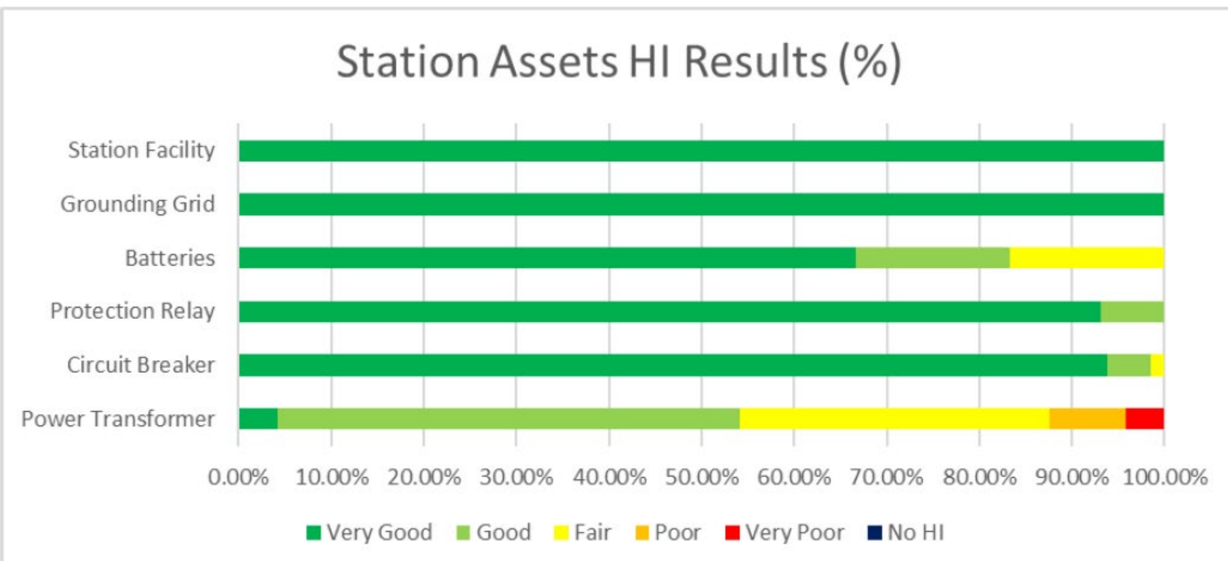


Figure 17: Summary of Health Index Results for Substation Assets



3.2.4 SYSTEM UTILIZATION (5.2.3D)

CNPI's 2020 Area Planning Study ("APS"), provided as Appendix E, describes CNPI's system planning standards and performance criteria. As described in Section 4.4 of the APS, evaluating contingency scenarios related to substations and feeders is critical to ensuring that CNPI is able to restore power within a reasonable period of time and with acceptable power quality parameters following the failure of any single asset. From a substation perspective, contingency analysis generally involves running load flow simulations with the single largest transformer at each substation removed from service (one asset out of service at a time). Table 21 below summarizes the utilization of each of CNPI's distribution substations by comparing the peak station load to the contingency capacity.

The utilization summary presented in Table 21 is a simplified summary as it pertains to contingency planning and utilization for substation power transformers, which are among the most expensive and difficult to replace assets and are therefore critical to contingency planning. The contingency analysis contained in the APS uses sophisticated engineering analysis software to consider addition complexities such as the availability and capacity of nearby feeders to perform load transfers, and the resulting loads and voltage levels at all points on the distribution system after such load transfers are completed. The APS also considers likely changes in load resulting from load growth projections and completion of voltage conversion programs which either gradually shift load from one station to another (e.g. Fort Erie 4.8 kV Delta to 8.3 kV Wye conversion), or offload certain stations completely (e.g. 4.16 to 27.6 kV conversions). The APS discusses the extent to which asset utilization and contingency planning considerations have influenced CNPI's actual capital investments in the historical period and planned capital investments in the forecast period.

Table 21: Summary of Substation Utilization Under N-1 Contingency

Area	Station	Contingency Capacity (MW)	Peak Load (MW)	N-1 % Utilization
FE	Gilmore DS	10	4.71	47%
FE	Station 12 DS	13.5	9.25	69%
FE	Station 19 DS	13.3	11.59	87%
PC	Beach (Sherkston) DS	5	3	60%
PC	Catharine DS + Jefferson DS	Single-Element – See APS		
PC	Fielden DS	6.5	3.45	53%
PC	Killaly DS	4	2.91	73%
EOP	Downtown (Gananoque DS)	5	5.21	104%
EOP	Herbert DS	6	3.71	62%
EOP	Main DS	33	11.28	34%

3.3 ASSET LIFECYCLE OPTIMIZATION POLICIES AND PRACTICES (5.3.3)

3.3.1 ASSET LIFECYCLE OPTIMIZATION POLICIES AND PRACTICES (5.3.3A)

CNPI's asset lifecycle optimization practices include consideration of overall inspection, maintenance, repair and replacement requirements for each type of asset over its expected life. The optimal balance of these activities will depend on factors such as:

- The number, type, condition, and criticality of the assets in service;
- Minimum inspection and maintenance requirements according to DSC requirements, manufacturer's recommendations and Good Utility Practice;
- Health, safety and environmental requirements;
- Risk of Failure (safety, environmental, reliability, cost etc.);
- Availability of spare equipment and evaluation of contingency plans;
- Analysis, by asset type, of available options to refurbish vs. replace existing assets;
- Replacement prior to end of life due to factors beyond CNPI's control (e.g. storm damage, vehicle accidents, vandalism, changes to standards or regulations, unexpected customer demand work, road relocations, etc.)

Additional programs such as infrared scanning, pole testing and transformer DGA are used to more accurately identify the condition and the probability of failure for more critical assets. Where the results of inspections identify issues requiring immediate attention, corrective maintenance and/or asset replacement is undertaken. Less immediate issues are addressed through future maintenance or capital programs.

CNPI's preventative maintenance programs consist of regularly scheduled activities based on manufacturer's recommendations and Good Utility Practice. This includes activities such as removing equipment from service for replacement of specific components, detailed electrical testing, cleaning, lubrication, etc. Details of CNPI's major in-service distribution assets, as well as full details of the inspection and maintenance programs in place for each type of asset can be found in CNPI's AMP, included as Appendix A. Section 4.2 of this DSP describes how the output of the inspection and maintenance programs factors into CNPI's future capital and maintenance planning.

CNPI sustains its planning process through the lens of long-term (15-year), medium-term (5-year), and short-term (1-year) planning. Annual review of these plans allows the utility to prioritize investments and reach decisions regarding repair vs. replace, new-builds, or allow for reallocation of funding to higher priority investments. The long-term approach focuses on high-level reviews, such as system planning studies, in conjunction with load growth and voltage data to assure that the system will maintain overall levels of available capacity, reliability, power quality and safety for CNPI's customers. Medium-term planning is driven by customer, municipal, health, safety, environmental, regulatory, reliability, and other needs that CNPI must service. Medium-term planning also incorporates changes in overall asset condition, as identified through ongoing inspection and maintenance programs, including reviewing the effectiveness of maintenance programs and adjustments as required. Short-term planning confirms or reprioritizes capital and maintenance projects identified within the 5-year plan, considering factors such as requests for new customer connections or service upgrades, consideration of recent trends and emerging issues from outage analysis and O&M inspections, and consideration how specific projects or programs relate to CNPI's overall system planning and asset management objectives as identified throughout this DSP.

3.3.2 ASSET LIFECYCLE RISK MANAGEMENT POLICIES AND PRACTICES (5.3.3B)

The optimal balance of inspection, maintenance, repair and planned replacement varies by asset type and sub-type. Critical assets, such as substation transformers, undergo frequent inspection and preventative maintenance programs throughout their life. On the other hand, assets such as insulators and most pole hardware are visually inspected in accordance with the DSC mandated frequencies but are not otherwise inspected or maintained. These assets are generally replaced on failure, or at the time of the planned replacement of the associated pole. The following section describes CNPI's lifecycle optimization practices by asset type.

POLES

CNPI conducts visual inspections of its distribution feeders on a 3-year cycle in accordance with DSC Appendix C requirements. The visual inspections are carried out by internal resources, with poles identified and prioritized for replacement in cases where major deficiencies (e.g. significant levels of rot or damage) are apparent during the visual inspections.

In addition to visual inspection requirements prescribed by the DSC, CNPI retains third-party contractors to perform detailed pole testing that includes a combination of visual inspection and estimation of residual wood fibre strength determined through a series of tests and measurements on each individual pole. CNPI's 2020 ACA incorporated available pole testing results for 5,914 poles, or 25% of CNPI's total pole population. CNPI received testing results in late 2020 for a further 7,093 poles tested in the 2018-2020 period, such that 55% of its total poles have now been tested. Third-party pole testing continues to target specific areas of CNPI's distribution system on an annual basis, with an expectation that remaining areas will be tested between 2021 and 2023, at which point CNPI will consider the appropriate pace for its next pole testing cycle.

As summarized in Figure 16 (Section 3.2.3), CNPI has few poles in very poor condition (i.e. requiring immediate replacement). However, approximately one-third of CNPI's poles have a health index score in the Poor range, indicating that planning for pole replacements should be initiated with consideration of failure risk and consequences. This result aligns with CNPI's System Renewal investment strategy over the historical and forecast periods, to focus on projects that incorporate both asset and of life considerations as well as performance outcomes related to safety, reliability and power quality. Examples include ongoing voltage conversion programs, rebuilding radial supplies to various areas, and replacing undersized conductor to improve contingency options.

Due to the high number of in-service poles, and the consequence of failure, CNPI employs a proactive replacement strategy for this asset. This is intended to replace the majority of poles prior to in-service failure or remaining strength that is below relevant CSA specifications. This also ensures that the associated components (insulators, hardware, crossarms, grounding, guying, etc.) remain intact without major issues for the lifecycle of each pole. Reducing line rebuild and pole replacement levels in the System Renewal category would be expected to result in more poles or associated components failing in-service than are currently observed, meaning potentially large outages and public safety issues, and higher incremental costs for reactionary repair and replacement work.

OVERHEAD CONDUCTOR

Conductors are inspected as part of the regular feeder inspections mandated in the DSC. Other than visual inspections and infrared scanning to identify hot spots, there are few options for additional in-service testing or maintenance of overhead conductors. Deficiencies noted during feeder inspections are identified through exception-based reporting and are prioritized for repair as required.

Conductors are generally repaired via splices as they fail, for example as a result of tree contact, or replaced in conjunction with overall line rebuilds. Since CNPI has generally been able to align line rebuild and voltage conversion projects in a manner that addresses asset end of life considerations over wide areas and longer line segments, CNPI generally replaces overhead conductor during these rebuild activities. The replacement poles and conductors and designed and installed as an integrated system to ensure that the poles and wire will withstand physical forces (e.g. ice and wind loads) according to design standards, and that the resulting electrical ratings will provide sufficient capacity and power quality during both normal loading and foreseeable contingency conditions.

An exception to this conductor replacement practice is that in cases where one-off pole replacements are required (e.g. based on inspection and testing results, damage from vehicle accident, etc.) the associated overhead conductor is typically transferred to the new pole instead of being replaced.

UNDERGROUND CABLE ASSETS

Any readily accessible portions of underground systems, such as terminations in pad-mounted equipment and junction boxes is included in CNPI's multi-year feeder inspections, which include infrared scanning. Deficiencies noted during feeder inspections are identified through exception-based reporting and are prioritized for repair as required.

CNPI's primary underground conductor comprises less than 10% of CNPI's total primary feeder length and much of this conductor is associated with newer subdivisions. At this point in time, the likeliest points of failure are terminations and splices that are captures during feeder patrols. As CNPI's primary underground system ages, reliability trends will be monitored to determine when additional testing methods such as periodic electrical testing of underground cables is warranted.

POLE LINE HARDWARE

This group of assets includes items such as crossarms, insulators, hardware, fused cutouts, anchoring and guying components, grounding components, etc. These assets are inspected during visual feeder patrols. In the absence of deficiencies being identified during feeder patrols, these components are normally run to failure or replaced in conjunction with planned pole replacements. These components will typically provide reliable service from the initial pole installation to the time of planned total pole replacement. On occasion, groups of components are identified that require proactive replacement outside of being replaced with the associated pole. An example would be where manufacturing defects or design issues are identified in certain lots or types of material that pose higher risks of failure or exhibit safety issues to workers or the public for the in-service asset.

DISTRIBUTION TRANSFORMERS

Overhead transformers are inspected visually during regular feeder patrols, as well as on an ad-hoc basis during other planned work such as service connections or disconnections.

Due to the large number of in-service distribution transformers, it would be extremely impractical to closely monitor and maintain pole-top and pad-mount transformers in the same fashion as substation power transformers, and the expense of such a program would far exceed its utility.

The consequence of failure of any individual pole-top or pad-mount transformer is relatively low. CNPI also maintains an adequate inventory of spare transformers which allows for immediate replacement of failed units.

Situations where CNPI will proactively replace distribution transformers that have not failed in-service include:

- Voltage conversion – transformers are replaced as required during voltage conversion projects to match the new system voltage level.[15]
- Overloading – distribution transformers identified as being overloaded, or those that would have a high probability of future overloading due to the connection of new services or service upgrades are proactively exchanged for a larger size transformer.
- Near end-of-life – transformers at end of life, are removed from service during otherwise planned activities. This eliminates the higher future costs associated with a one-time trip for the sole purpose of exchanging a failed transformer.

Transformers that are replaced for reasons unrelated to end of life (voltage conversion and potential overloading) are inspected and tested. If the transformer is in good condition and otherwise suitable for re-use, it is returned to inventory as a spare for future use.

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[15] Transformers in good condition can be re-used in place during 4.8 kV Delta to 4.8/8.3 kV Wye voltage conversions, whereas other voltage conversion projects require transformer replacements.

RECLOSERS, VOLTAGE REGULATORS, GANG-OPERATED SWITCHES

The assets in this category are relatively small in number and critical to the proper operation of the distribution system. In-service failure could result in widespread outages, power quality issues, as well as potential safety or environmental issues. As a result, there are regular inspection and preventative maintenance programs associated with these assets.

The more critical assets in this category are subjected to corrective maintenance based on the outcome of infrared scanning. Where equipment can by bypassed, regular operational checks (i.e. manually verifying proper operational capability) are also conducted on defined cycles. In addition, many of these assets are removed from service for more detailed testing, repairs, and overhauls, as required. Specific details on the inspection and maintenance programs in place for each type of asset can be found in Section 4 of CNPI's AMP.

Due to the costs associated with both the initial purchase and ongoing maintenance of these assets, decisions to replace vs repair the assets are often required. For example, time-consuming repairs and component replacement associated with hydraulic recloser repair, or repair of older gang-operated switches, may result in replacement being the more economical option. Replacement units often provide improved functionality (more accurate operation/timing, ability to change parameters to replace multiple variations of legacy equipment, SCADA-ready, etc.) and also require less future maintenance than a repaired unit. As a result, CNPI has incorporated replacement of some of these assets into its Distribution Automation and Reliability programs as it targets reliability improvement in specific area.

SUBSTATION POWER TRANSFORMERS

Substation power transformers are generally among the most expensive distribution assets. They also have a high consequence of failure in terms of potential safety and environmental impacts, outage impacts and replacement costs. A single transformer failure could result in a prolonged outage to thousands of customers, with extensive restoration time if the outage impacts an area with limited load transfer capability. Even in areas with supply redundancy, the long lead time for replacement following a failure would result in a significant increase in long-duration outage risk following a station transformer failure. The combination of the high value, criticality, and small number of in-service assets, justifies more intensive inspection and maintenance programs for these assets.

CNPI's power transformers are inspected monthly, including visual inspections of the overall condition of transformers are related equipment and recording of any gauges or counters. Annually, all substation assets are scanned using infrared cameras and have oil samples taken for dissolved gas analysis. Any issues identified during an inspection process are noted and prioritized for corrective maintenance or additional detailed electrical testing as required.

These assets are generally replaced proactively when results of inspection and maintenance activities suggest that there is an increasing probability of failure in the near future, with consideration of available contingency options and spare equipment.

SUBSTATION SWITCHING AND PROTECTION ASSETS

Substation switching and protection assets are similarly high-value and low in quantity, with a higher consequence of failure than most other asset types. These assets are also inspected monthly, including visual inspections of the overall condition of transformers are related equipment and recording of any gauges or counters. Annually, all substation assets are scanned using infrared cameras and have oil samples taken for dissolved gas analysis. Any issues identified during an inspection process are noted and prioritized for corrective maintenance or additional detailed electrical testing as required. Due to the variety of assets and configurations currently in use, repair vs. replacement decisions are made on a case-by-case basis.

Configurations for recent substation construction and upgrades have been designed with protection and switching redundancy where practical (e.g. bus separation and distinct protection/switching for each power transformer) to facilitate testing, maintenance and repair activities without customer outages. Where equipment ratings and station configuration permits, CNPI has increasingly employed solid-dielectric substation reclosers with vacuum-interrupters, as these devices are generally more cost-effective and require less maintenance than traditional circuit breakers or metal-clad switchgear.

OTHER SUBSTATION ASSETS

This group of assets includes the general substation site, control buildings, batteries, secondary electrical and control systems, fencing, structures and foundations, buswork, insulators, hardware, etc. These items are also included in monthly inspections, with some assets such as batteries being subject to further periodic testing and maintenance. Deficiencies are recorded on inspection forms and prioritized for repair as required. These assets are generally maintained and repaired throughout the life of the overall substation, with some components such as batteries being replaced on a more frequent basis.

Further details of CNPI's substation inspection and maintenance programs can be found in Section 4 of CNPI's AMP.

METERING ASSETS – AMI

CNPI utilizes the Sensus FlexNet Advanced Metering Infrastructure (AMI) system in order to meet the requirements of the provincial smart metering mandate. The AMI communications network currently consists of the following equipment:

- 5 Tower Gateway Base-stations ("TGBs"): 3 in the Niagara area and 2 in the Gananoque area
- 1 Repeater in the Gananoque area

TGBs are relatively expensive assets that comprise complex transceiver units housed in weatherproof enclosures, with integrated heating, ventilation and air conditioning (HVAC) systems and battery backup. Each TGB typically reads thousands of meters. As part of the long-term AMI contract with Sensus, these units are remotely monitored on a 24/7 basis, and preventive maintenance activities are performed by Sensus semi-annually. Maintenance includes changing air filters, verifying correct operation of all HVAC and power systems, and firmware upgrades as required. Sensus is responsible for any repairs to these units during the term of the AMI contract.

Repeaters are pole-mounted devices that are used to read meters in areas where TGB coverage is marginal or unavailable. These devices are monitored for communication uplink availability, with alarms sent to CNPI in the event that communications are lost. Given the relatively low number of meters relying on each repeater, issues are corrected only as identified. Spare equipment is readily available, and replacement can generally occur prior to the loss of any Time-of-Use (TOU) consumption data.

METERS AND INSTRUMENT TRANSFORMERS

Meters follow a certification maintenance program as they are subject to re-verification regulations made under the Electricity and Gas Inspection Act. CNPI samples meters in accordance with regulatory requirements and will keep meters in service if they continue to meet regulatory requirements. Larger services and complex meter installations are also subject to periodic verification and testing where instrument transformers and the overall wiring of the metering installation are tested in conjunction with the associated meters.

Wholesale metering installations are subject to the requirements of the IESO's Market Rules. CNPI's Meter Service Provider (MSP) manages the periodic re-verification and replacement of meters as required to meet Market Rules. The MSP also reviews data from these meters and flags any potential data integrity issues for further investigation.

FLEET

In order to support the day-to-day activities of operations crews and other staff based in its Fort Erie and Gananoque work centres, CNPI maintains a fleet that consists of:

- 14 aerial devices (bucket trucks, radial boom derricks)
- 28 cargo vans, pickup trucks and passenger vehicles
- 15 trailers (open & enclosed) – for transporting poles, heavy materials, etc.
- Other equipment such as forklifts, tensioning equipment, wood chipper, etc.

CNPI has developed and implemented a preventative fleet maintenance plan in its SAP work management system that complies with manufacturers recommendations and prescribed regulations.

Maintenance of booms for hoisting and man lifts (buckets) includes requirements for a variety of one month, 3-month, 6-month and annual inspections, including dielectric testing. Cab and chassis have separate inspection requirements that are similar in frequency. Additionally, regulations prescribe annual commercial vehicle operator's registration (CVOR) inspections and emissions testing.

Maintenance of pick-up trucks generally includes 3-month service requirements and annual Safety Inspections. Heavier vehicles are subject to CVOR inspections and emissions testing.

Annual fleet replacements typically include one aerial device, as well as a number of smaller approximately 3-6 smaller vehicles and miscellaneous equipment as required. Replacement decisions are based on evaluation of age, total km, condition assessment and evaluation of maintenance costs.

RIGHTS OF WAY (ROW)

CNPI's distribution rights of way assets are generally maintained through cyclical maintenance programs as opposed to capital investments. CNPI maintains its distribution rights of way on a 3-year cycle for limb and branch removal or trimming along its entire overhead distribution system. Spot trimming or branch removal is also performed in any specific areas where faster-than-typical growth has occurred or one or more damaged branches have entered the minimum clearance zone around overhead conductors.

CNPI's 3-year tree trimming cycles are generally aligned with the feeder inspection zones discussed above. CNPI's AMP provides further detail and the standards applicable to CNPI's vegetation management program.

3.4 SYSTEM CAPABILITY ASSESSMENT FOR RENEWABLE ENERGY GENERATION (5.3.4)

As of December 31, 2020, CNPI has 4 FIT installations with a total capacity of 1,163 kW and 201 microFIT projects with a total capacity of approximately 1,862 kW connected to its distribution system. All of these projects were connected between 2010 and 2018.

3.4.1 APPLICATIONS OVER 10 KW (5.3.4A)

CNPI does not currently have any active applications for connection of embedded renewable energy generation.

3.4.2 FORECAST OF REG CONNECTIONS (5.3.4B)

Since the IESO ceased accepting new applications under the FIT and microFIT programs, CNPI has seen a significant decrease in interest in connecting REG projects to its distribution system. Currently, settlement options for any new embedded generation project are limited to net metering, load displacement, or settlement as an embedded retail generator under the Retail Settlement Code. In recent years, CNPI has seen a limited number of new net metering installations (which typically export very little power to CNPI's system) and load displacement installations (which generally do not export power to CNPI's system).

Based on the limited incentives/initiatives currently available, CNPI forecasts that REG connections during the period covered by this DSP will continue to be limited to a small number of net metering and load displacement projects.

3.4.3 CAPACITY AVAILABLE (5.3.4C)

Existing embedded generators (FIT, microFIT, merchant generators in Gananoque, load displacement generation in Niagara, etc.) are widely distributed across CNPI's distribution system. To date, the combined output of embedded generation in any specific area generally remains at or below normal feeder loads and equipment ratings.

Section 3.2.4 above provides a summary of system capacity at CNPI's various distribution substations. The specific capacity to connect embedded generation on any particular feeder would typically be limited by power quality and protection concerns prior to the total amount of embedded generation reaching these equipment ratings. As discussed in the following section, the presence of higher voltage feeders throughout CNPI's service areas would typically allow larger embedded generators to connect upstream of CNPI's distribution substations.

3.4.4 CONSTRAINTS – DISTRIBUTION AND UPSTREAM (5.3.4D)

CNPI receives its distribution supply at 34.5 kV in Fort Erie and at 27.6 kV in Port Colborne. In Gananoque, CNPI steps down its 44 kV supply to 27.6 kV. The system maps provided in CNPI's AMP show the location of these higher voltage feeders throughout CNPI's service areas.

To the extent that any mid to large-size REG projects are unable to connect to lower voltage (i.e. <15 kV class) feeders, CNPI expects that the most economical alternative for connection would involve a line extension to connect to the nearest higher voltage (i.e. 27.6 or 34.5 kV) feeder. The cost responsibility for any such expansions would be determined in accordance with the renewable energy cost cap provisions of the Distribution System Code on a case-by-case basis.

CNPI is not aware of any specific upstream capacity constraints that would prevent connection of REG projects embedded within its distribution system. With the removal of incentive programs that encouraged very large REG projects to connect to distribution systems, CNPI anticipates that any such projects would pursue more economical options to connect directly to the transmission system and that any limitations would be addressed through regional and bulk system planning processes as required.

3.4.5 CONSTRAINTS – EMBEDDED DISTRIBUTOR (5.3.4E)

For the small portion of HONI distribution load embedded on CNPI's 43M13 feeder in Port Colborne, the CNPI distribution system would not have any additional or unusual constraints as compared to other 27.6 kV connections. Similarly, for on the HONI 44 kV system supplying CNPI in Gananoque, CNPI is not aware of any upstream constraints beyond typical 44 kV equipment and feeder ratings.

4 CAPITAL EXPENDITURE PLAN (5.4)

This section describes CNPI's 5-year Capital Expenditure plan over the forecast period, including:

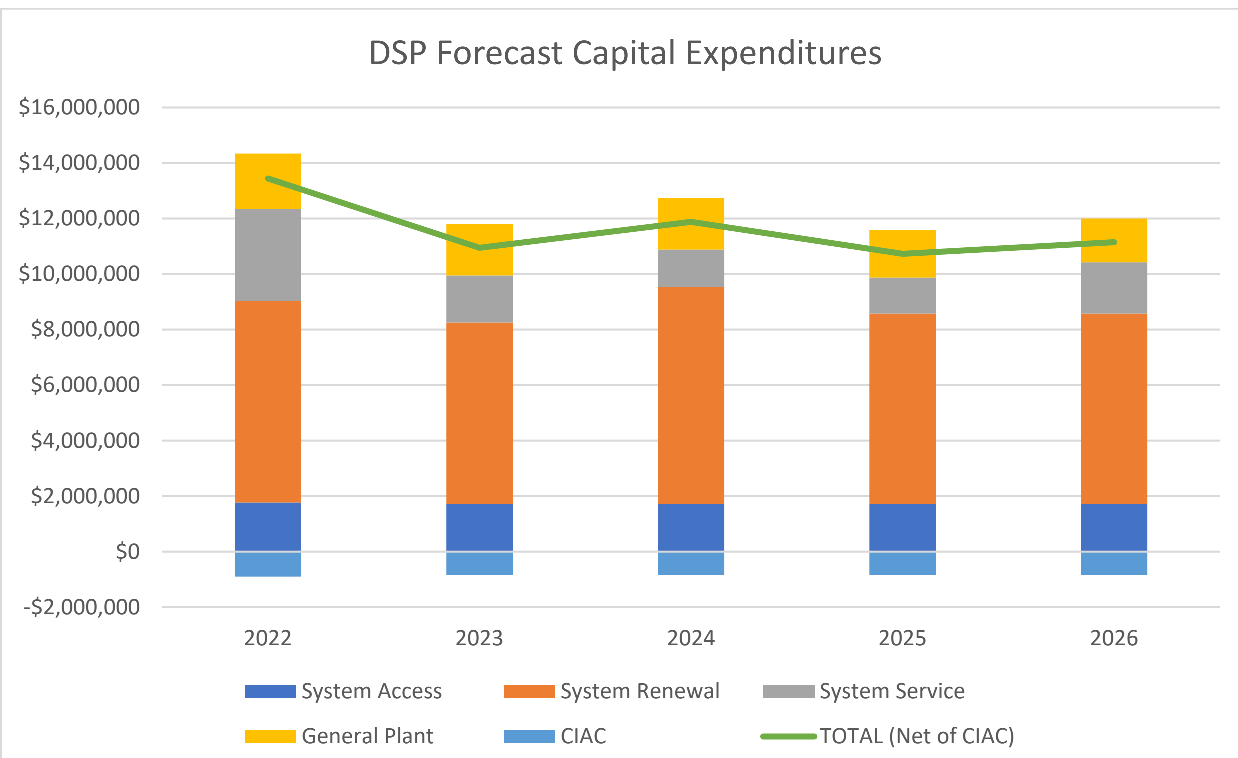
- A summary of the CNPI's plan, with reference to customer engagement activities and the evolution of CNPI's distribution system over the historical and forecast peiods (Section 4.1);
- Details of CNPI's Capital Expenditure planning process, including interactions with the AMP described in Section 3 (Section 4.2);
- An overall summary of 2017-2026 Capital Expenditures with detailed variance analysis for the historical period (Section 4.3); and,
- Justification of forecasted Capital Expenditures (Section 4.4).

4.1 SUMMARY

4.1.1 CAPITAL EXPENDITURES OVER THE FORECAST PERIOD

The following figure summarizes the planned Capital Expenditures for the DSP forecast period.

Figure 18: 2022-2026 Forecast Capital Expenditures by Category



4.1.2 2022-2026 CAPITAL INVESTMENTS BY CATEGORY 2022-2026

The following sections summarize CNPI's capital investment forecast by category for the forecast period. See Section 4.4 for detailed justification of material projects and programs within each investment category.

4.1.2.1 SYSTEM ACCESS

System Access investments primarily relate to distribution system expansions, upgrades and modifications that CNPI is required to undertake in order to connect customers to its distribution system or accommodate changes to existing services. CNPI has experienced a higher volume of connection requests in recent years, particularly as it relates to new subdivisions and multi-unit developments. Because similar levels of residential development in 2022 and beyond are possible, but not guaranteed, CNPI has forecasted service connection investments for the 2022-2026 period lower than recent actual activity.

System Access investments also include line rebuilds or relocations that are required to meet the needs of local road authorities in relation to road widening and relocation projects, as well of the needs of joint-use tenants in relation to expansions and upgrades of telecommunication systems attached to CNPI's poles. These projects can result in significant annual variability in CNPI's System Access investment levels.

Actual 2022-2026 System Access investments will depend on the level of customer and third-party demand. CNPI is prepared to increase investments in this category as required, while maintaining investment levels in other categories and expects that an increase in demand work will result in increased Contributions in Aid of Construction (CIAC) from customers and third parties, as well as increased distribution revenue for customer-driven work.

Table 22 provides a breakdown of CNPI's System Access investments over the forecast period.

Table 22: 2022-2026 System Access Investments ($000's)

SA Project/Program	2022	2023	2024	2025	2026
Service Connections (Incl Subdivisions)	1,000	979	979	979	979
Meters	393	359	351	352	352
Transformers - SA	80	80	80	80	80
Relocations, Joint-Use	299	300	300	300	300
Total	**1,771**	**1,718**	**1,710**	**1,711**	**1,711**

4.1.2.2 SYSTEM RENEWAL

System Renewal investments involve replacing end of life distribution assets and refurbishing system assets to extend the original service life. These investments maintain the ability of CNPI's distribution system to supply customers with safe and reliable electricity.

CNPI's System Renewal investments over the forecast period include the following:

- Distribution line rebuilds and line upgrades related to end of life asset replacement;
- Distribution line and substation rebuilds associated with ongoing voltage conversion efforts, which are integrated with end of life asset replacement and other capital planning considerations;
- Targeted pole replacement based on pole testing results and feeder inspections;
- Replacement of other individual distribution line or substation assets where test results or deficiencies identify requirements for priority replacements; and,
- Transformer replacements due to failure, end of life or voltage conversion.

Table 23 provides a breakdown of CNPI's System Access investments over the forecast period.

Table 23: 2022-2026 System Renewal Investments

SR Project/Program	2022	2023	2024	2025	2026
Lines					
Voltage Conversion (SR)	2,296	3,250	2,550	2,750	2,750
Line Rebuilds/Upgrades/Replacements	3,197	2,462	2,741	3,357	3,357
Stations					
Station 12 / Oakes DS	-	175	1,800	-	-
Port Colborne TS Rebuild	176	-	-	-	-
Gananoque Distributed Stations	300	-	-	-	-
Sherkston DS Transformer	300	-	-	-	-
Other					
Transformers - SR	612	560	565	568	568
Other	379	90	170	190	190
Total	**7,259**	**6,537**	**7,826**	**6,865**	**6,865**

4.1.2.3 SYSTEM SERVICE

System Service investments involve modifications or additions to CNPI's distribution system to improve system reliability, improve power quality, and reduce system losses.

CNPI's System Service investments over the forecast period include the following:

- Installation of additional protection and control equipment and distribution automation schemes to improve reliability and outage response;
- Portions of voltage conversion activity that do not fall under the System Renewal category;
- Construction of a new distribution substation in Stevensville; and,
- Investments to reduce contingency risk as identified through area planning studies.

Table 24 provides a breakdown of CNPI's System Access investments over the forecast period.

Table 24: 2022-2026 System Service Investments

SS Project/Program	2022	2023	2024	2025	2026
Lines					
Voltage Conversion (SS)	752	500	600	700	750
Line Rebuilds/Upgrades/Replacements (SS)	118	250	250	100	100
Stations					
Stevensville DS	1,417	-	-	-	-
Station 19 Projects (SS)	148	-	-	-	-
67RT3 - New Backup RB on F1911	-	200	-	-	-
Killaly DS	-	-	-	-	500
Other					
Distribution Automation and Reliability	714	650	400	400	400
Other	157	95	95	95	95
Total	**3,305**	**1,695**	**1,345**	**1,295**	**1,845**

4.1.2.4 GENERAL PLANT

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

CNPI's General Plant investments over the forecast period include the following:

- End of life replacements of fleet, IT hardware and other equipment;
- Software upgrades and licensing;
- CIS System (SAP) upgrades and development; and,
- Sustaining investments and leasehold improvements in facilities.

Table 25 provides a breakdown of CNPI's System Access investments over the forecast period.

Table 25: 2022-2026 General Plant Investments

GP Project/Program	2022	2023	2024	2025	2026
IT Software	901	1,250	800	800	700
IT Hardware	199	200	200	150	120
Fleet	545	120	505	462	462
Facilities, Yards, Land	231	115	185	135	135
Other	131	161	161	161	161
Total	**2,007**	**1,846**	**1,851**	**1,708**	**1,578**

4.1.3 CUSTOMER ENGAGEMENT AND PREFERENCES ACTIVITIES (5.4A)

This section summarizes how CNPI engaged with its customers to inform the development of this DSP, and the results of those engagement activities. Customer engagement is one among many inputs to CNPI's overall capital planning process, with must also consider CNPI's AMP, non-discretionary projects, input from other stakeholders, and the results of system planning studies.

4.1.3.1 CUSTOMER ENGAGEMENT ACTIVITIES

CNPI employs a variety of communication channels to inform and engage with its customers, employees, communities, other stakeholders and third parties on a regular basis. This includes regular bill inserts, presence on social media platforms, website updates, customer portals, community and contractor meetings, participation in regional planning efforts, and participation in community events. CNPI's customer engagement activities are summarized in various sections of its 2022 Cost of Service Application, as well as in the "Taking A.I.M. (Applied Insights Methodology)" report prepared for CNPI by UtilityPULSE.[16]

In order to engage with customers specifically in relation to this DSP, CNPI worked with UtilityPULSE to review the findings and trends from prior customer surveys and create two online surveys designed to gather wisdom, information, feedback and insights from respondents. The structure and themes for these online surveys are summarized in the following table.

[16] See Section 1.6 of Exhibit 1 and OEB Appendix 2-AC for summaries of CNPI's customer engagement activity. The Taking A.I.M. report is included in CNPI's Business Plan, which is filed as Appendix 1-B to Exhibit 1.

Table 26: Online Survey Structure and Themes

Online Survey ONE	Primary Theme
Chapter Survey 1 *"Overall market context and CNP/EOP"*	Wisdom from Customers
Chapter Survey 2 *"How the electricity industry works and Canadian Niagara Power's / Eastern Ontario Power' role in it"*	Test your knowledge
Chapter Survey 3 *"Help Canadian Niagara Power / Eastern Ontario Power understand our customer's priorities"*	Could You Help Us Decide
Chapter Survey 4 *"Getting customer insights about billing and outages"*	Make Your Voice Count

Online Survey TWO	Primary Theme
Chapter Survey 5a *"Help us prioritize capital investments in the electricity network"*	Could You Help Us Decide
Chapter Survey 5b *"COS decision-making considerations – ranked items"*	Make Your Voice Count
Chapter Survey 6 *"Gathering insights about customer care operations"*	Could You Help Us Decide

4.1.3.2 CUSTOMER PREFERENCES – INVESTMENT LEVELS AND BILL IMPACTS

CNPI's first online survey was completed by 602 customers. This survey was generally designed to gain insight on customer impacts resulting from the COVID pandemic, communicate general information about CNPI, and gain insights related to customer priorities and perceptions. The results of the first online survey helped CNPI and UtilityPULSE understand the priorities, perceptions and knowledge base of customers likely to complete online surveys. This allowed the design of the second online survey to consider how to present the proposed investments and priorities from CNPI's DSP in a way that was understandable and relevant to customers that were likely to complete the second survey.

CNPI's second online survey focused on its 2022-2026 DSP, explaining the purpose of each capital investment category, and seeking customer feedback on the forecasted bill impacts associated with CNPI's proposed 2022-2026 capital investment levels in each category. CNPI also included a question to gauge customer support for increased O&M spending related to tree trimming as a means to improve reliability.

1240 customers responded to CNPI's second online survey, with one-third of customers indicating support for investments at or above the levels proposed by CNPI for all five categories. The vast majority of CNPI's customers seem to understand the non-discretionary nature of System Access investments.

For the System Renewal and General Plant categories, two-thirds of CNPI's customers supported investments at or above the levels proposed by CNPI. The remaining one-third of customers were split between supporting investments at a level that would result in lower bill impacts, supporting investments at a level that would result in no bill increases, or simply answered "don't know". Support for System Service investments was marginally lower (61% supporting investments at or above CNPI's proposed levels).

Customer support for CNPI's proposed increases to its tree trimming budget was significantly lower than support for its proposed capital investments. On closer examination of the results, an additional 28% of customers supported increases to tree trimming spending, but at levels below those proposed by CNPI.

Table 27 below summarizes CNPI's customer support for the proposed investment levels presented in the online survey. Figure 19 summarizes the overall support for rate increases relating to these investments.[17] Overall, the majority of CNPI's customers supported the capital investment levels proposed by CNPI, supported increases to tree trimming spending slightly lower than the levels proposed by CNPI. The median supported rate increase was approximately 10% lower than proposed by CNPI.

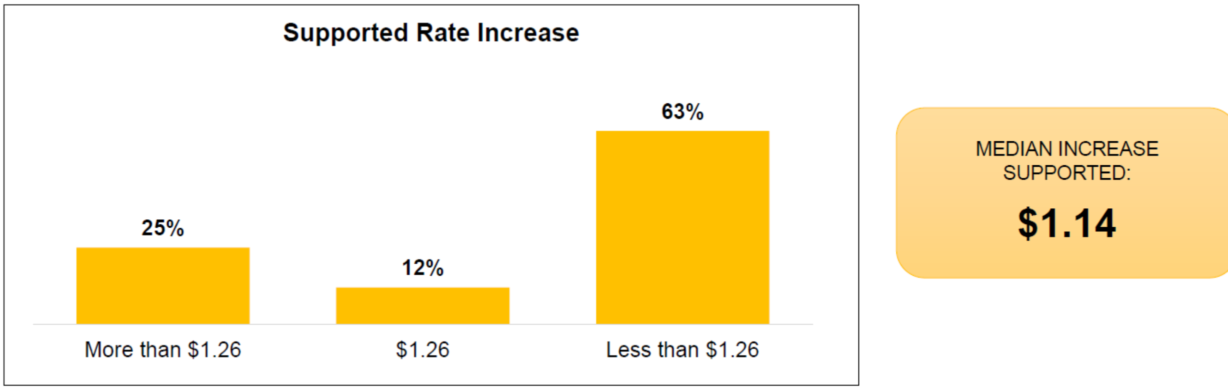
Table 27: Customer Support Levels by Investment Category

	No Increase #	No Increase %	Support CNPEOP's recommendations #	Support CNPEOP's recommendations %
System Access	87	7%	1,166	94%
System Renewal	112	9%	818	66%
System Service	124	10%	756	61%
General Plant	273	22%	818	66%
Tree Trimming	298	24%	471	38%
Support No Increase (in all 5 areas)	62	5%	--	--
Support CNP/EOP recommendations (in all 5 areas)	--	--	260	33%

Base: total respondents, online survey N=1,240

[17] In order to avoid the complexity of differentiating between IRM and cost of service rate setting in the customer surveys, CNPI presented capital investments by category as annual average investment levels over the 2022-2026 period and presented customers with the corresponding average annual increase to the residential monthly rate that would result from these investments (e.g. [(2027 residential rate resulting from proposed investments) – (2022 residential rate)] / 5].

Figure 19: Customer Support for Rate Impacts from Proposed Investment Levels

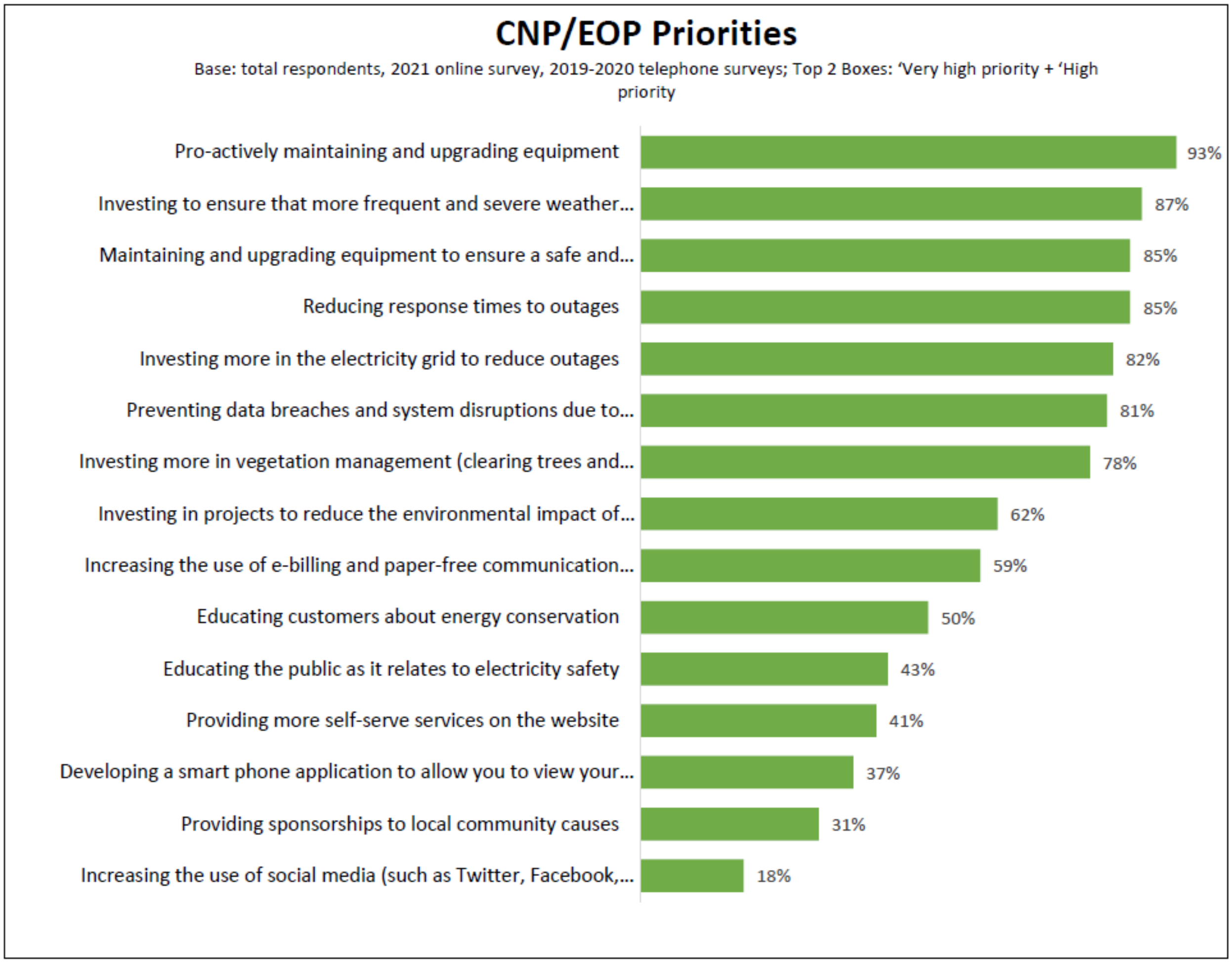


4.1.3.3 CUSTOMER PREFERENCES – SPECIFIC PRIORITIES

The results of CNPI first online survey, combined with the results of recent annual telephone surveys, also allowed CNPI to obtain insight in customer perspectives on investment and performance outcome priorities, prior to discussing costs in the second survey. These priorities are summarized in Figure 20 below. Three key themes emerged as priorities for the majority of CNPI's customers:

- Any category of investment intended to maintain or improve reliability was supported by the majority of customers.
- 81% of customers identified preventing data and system breaches as a priority.
- Reducing CNPI's environmental footprint is a priority for most customers, including increased use of e-billing and other paper-free communication, and education on energy conservation.

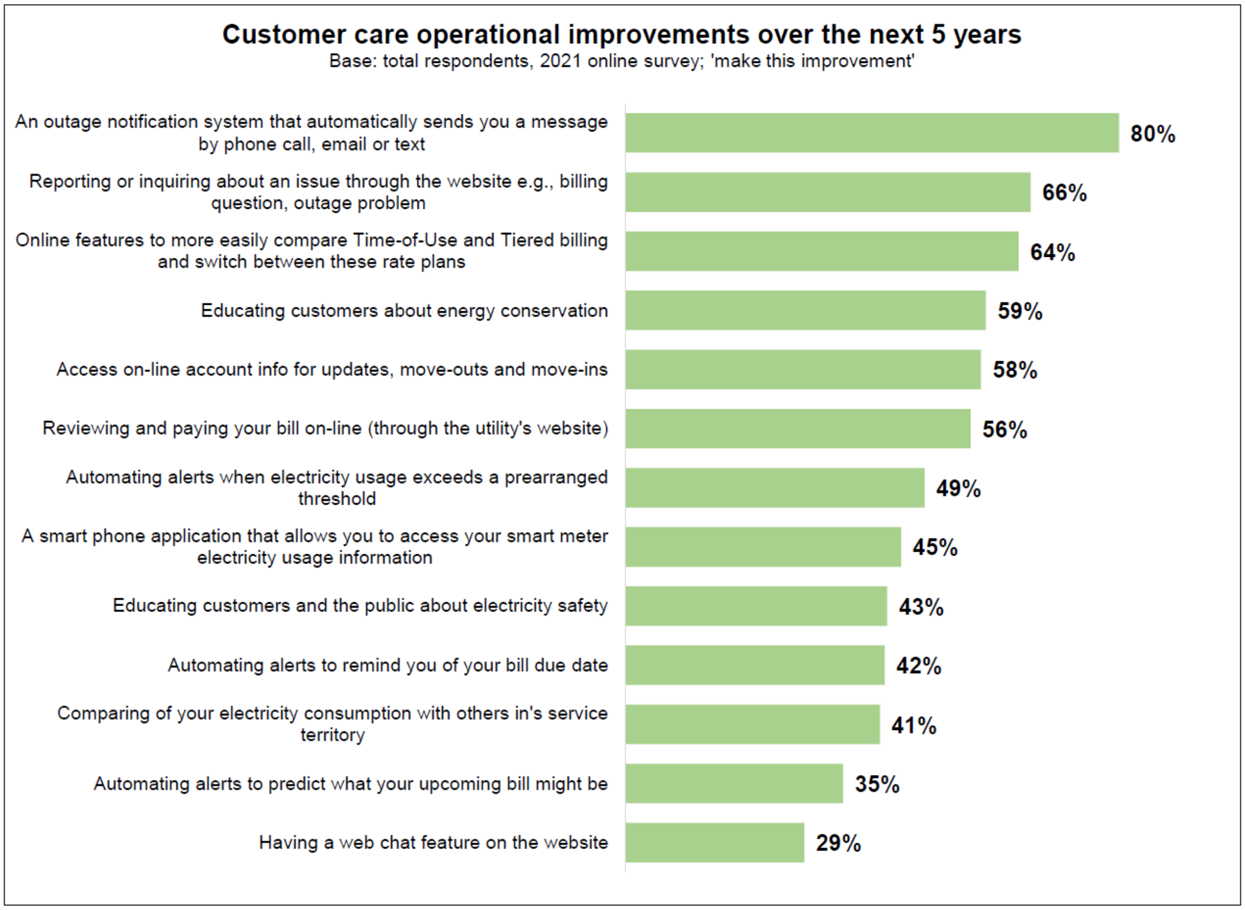
Figure 20: Customer Priorities – Types of Investments



Customer-facing activities such as education on electrical safety, increasing self-serve options and the use of technology, community sponsorships and increasing social media communication were all identified as priorities by less than half of CNPI's customers in the first online survey. In order to assess whether these items were simply lower priorities in the context of a list that included other higher-priority items, or were truly low priority, the second online survey included a chapter (Chapter 6) focused on gathering insights related to customer facing activities and projects. In this context, customers indicated a high degree of support for the following types of investments over the 2022-2026 period:

- Automated outage notification messages and other alerts
- Self-serve options and online forms
- Education on energy conservation

Figure 21: Customer Priorities – Customer Care Investments



4.1.4 SYSTEM DEVELOPMENT OVER THE FORECAST PERIOD (5.4B)

4.1.4.1 ABILITY TO CONNECT NEW LOAD AND REG PROJECTS

Section 3.2.4 above summarizes the capacity utilization of CNPI's distribution system and Section 3.4 confirms that there are no significant constraints related to connecting embedded generation. With plans in the forecast period to address contingency scenarios for substations with the highest utilization values, CNPI is confident in its ability to connect any typical request for new load or embedded generation within its distribution system. Requests for significantly large loads or generators may require connection to higher voltage feeders (i.e. 34.5 kV or 27.6 kV), and the cost responsibility for any resulting line extensions or upgrades would be addressed according to the system expansion provisions of the DSC.

4.1.4.2 LOAD AND CUSTOMER GROWTH

CNPI's weather normalized load forecast shows a slight increasing trend in residential load, resulting from annual residential customer growth of approximately 1% per year. This growth in the residential class is more than offset by a decreasing trend in commercial and industrial load, resulting from generally flat customer counts and significant participation in energy efficiency programs in recent years. While CNPI is confident in the methodology supporting its 2022 load forecast, changes in customer growth rates, availability of CDM programs and funding levels, and changes in peak demand due to extreme weather events all lead to increased uncertainty in system peak demand forecasts over the 2022-2026 period. CNPI has therefore considered the possibility of higher and lower growth scenarios in its area planning studies.

4.1.4.3 GRID MODERNIZATION

CNPI continues to increase integration between its various equipment and business systems with a goal of improving operational efficiency and customer service. Line and substation rebuilds over the historical period have increased the number of SCADA-capable devices deployed throughout CNPI's distribution system. Over the forecast period, CNPI expects to further increase the deployment of these devices coverage of distribution automation systems. Inspection and testing programs are increasingly being integrated with recently implemented GIS systems and area planning studies are making use of increasingly granular meter data as well as engineering analysis functionality integrated with the GIS system.

4.2 CAPITAL EXPENDITURE PLANNING PROCESS OVERVIEW (5.4.1)

4.2.1 PLANNING OBJECTIVES, ASSUMPTIONS, CRITERIA AND RISK MANAGEMENT (5.4.1A)

4.2.1.1 PLANNING OBJECTIVES

The fundamental objective of the AMP is to prudently and efficiently manage the planning and engineering, design, addition, inspection and maintenance, replacement, and retirement of all distribution assets in a sustainable manner that maximizes safety and customer reliability, while optimizing asset lifecycle costs. Using the AMP, Area Planning Studies ("APS") and other performance analysis as inputs, CNPI's overall system planning and capital expenditure planning process ensures that CNPI continues to provide the safe, reliable, and efficient distribution of electricity to its customers.

There are three key principles that are integral to CNPI's distribution system planning process:

1) Meet the needs and expectations of its customers, as identified through regular customer engagement;
2) Provide safe, reliable, and high-quality of service to all of the customers of CNPI; and
3) Satisfy the first two principles in a sustainable manner, with a focus on long-term value and performance outcomes.

Table 28 below illustrates how the asset management objectives and system planning principles identified above, as well as CNPI's core values (as identified in Section 1.3.1), relate to each other and to the RRFE performance outcomes established by the OEB.

Table 28: Performance Outcome Alignment with Planning Objectives and Core Values

RRFE Performance Outcome	CNPI Planning Objectives/Principles	CNPI Core Values
Customer Focus	Meet the needs and expectations of its customers, as identified through regular customer engagement; Provide safe, reliable, and high-quality service; Minimize long-term costs to be borne by ratepayers;	Customer Service Respect for People Inclusion and Diversity Community Involvement Safety and the Environment
Operational Effectiveness	*Prudently and efficiently* manage the planning and engineering, design, addition, inspection and maintenance, replacement, and retirement of all distribution assets in a sustainable manner	Customer Service Inclusion and Diversity Productivity
Public Policy Responsiveness	Principles are derived from safety considerations; *acts, regulations, codes and guidelines*	Safety and the Environment
Financial Performance	*Prudently and efficiently* manage the planning and engineering, design, addition, inspection and maintenance, replacement, and retirement *of all distribution assets in a sustainable manner*	Inclusion and Diversity Productivity Financial Success

4.2.1.2 PLANNING CRITERIA, ASSUMPTIONS AND RISK MANAGEMENT

CNPI's APS, included as Appendix E, identifies the assumptions, methodology, planning standards and limitations that factor into CNPI's system planning activities. This includes assumptions relating to system load, the types of contingency/emergency situations studies or excluded, acceptable ranges for system voltage levels and equipment loading, and assumptions made to allocate peak load in system models.

From a reliability risk management perspective, the results of the APS identify any equipment that is likely to become overloaded and any areas of CNPI's system that are unable to provide acceptable power quality under reasonably foreseeable conditions. The risk of each issue identified in the APS is considered in the overall prioritization of capital investments, along with the risks of failure associated with asset condition as identified through the AMP and ACA.

A number of additional assumptions and risks specific to each investment category are also considered:

SYSTEM ACCESS

CNPI has experience a higher than normal volume of customer-driven connection work in the historical period and has also experience large one-off road relocation and joint-use make-ready projects. Due to the cyclical nature of housing markets, CNPI has not carried the high volume of historical year activity into the forecast period. From a risk management perspective, CNPI is prepared to adjust resources and supplies as required to respond to any changes in System Access investment requirements while maintaining the pace and priority of investments in other categories.

SYSTEM RENEWAL AND SYSTEM SERVICE

CNPI's system renewal and system service investment forecasts are planned to address the needs identified in the APS, the AMP and ACA, as well as analysis of reliability and performance trends. To the extent practical, investments to address reliability issues, reduce contingency risk or improve system performance are aligned with asset end of life replacement requirements.

The forecasted investments in these categories are based on consideration of the most recent inputs available. Over the forecast period, the relative priority of identified projects may change, or projects to identify emerging issues may be identified, based on one or more of the following:

- Ongoing inspection, maintenance and testing programs will undoubtedly reveal changes in the condition of specific assets over time;
- Actual changes in system load may differ from assumptions made in the APS;
- Reliability trends may change over time; and/or,
- Sudden equipment failure may significantly change the risk profile of certain contingencies.

CNPI has forecasted certain investments at a program level (e.g. line rebuilds and upgrades, voltage conversions), with a forecast of priority area/projects/activities to be addressed within these programs. CNPI expects to regularly reprioritize the specific expenditures within these programs over the forecast period based on changes in relative priority.

GENERAL PLANT

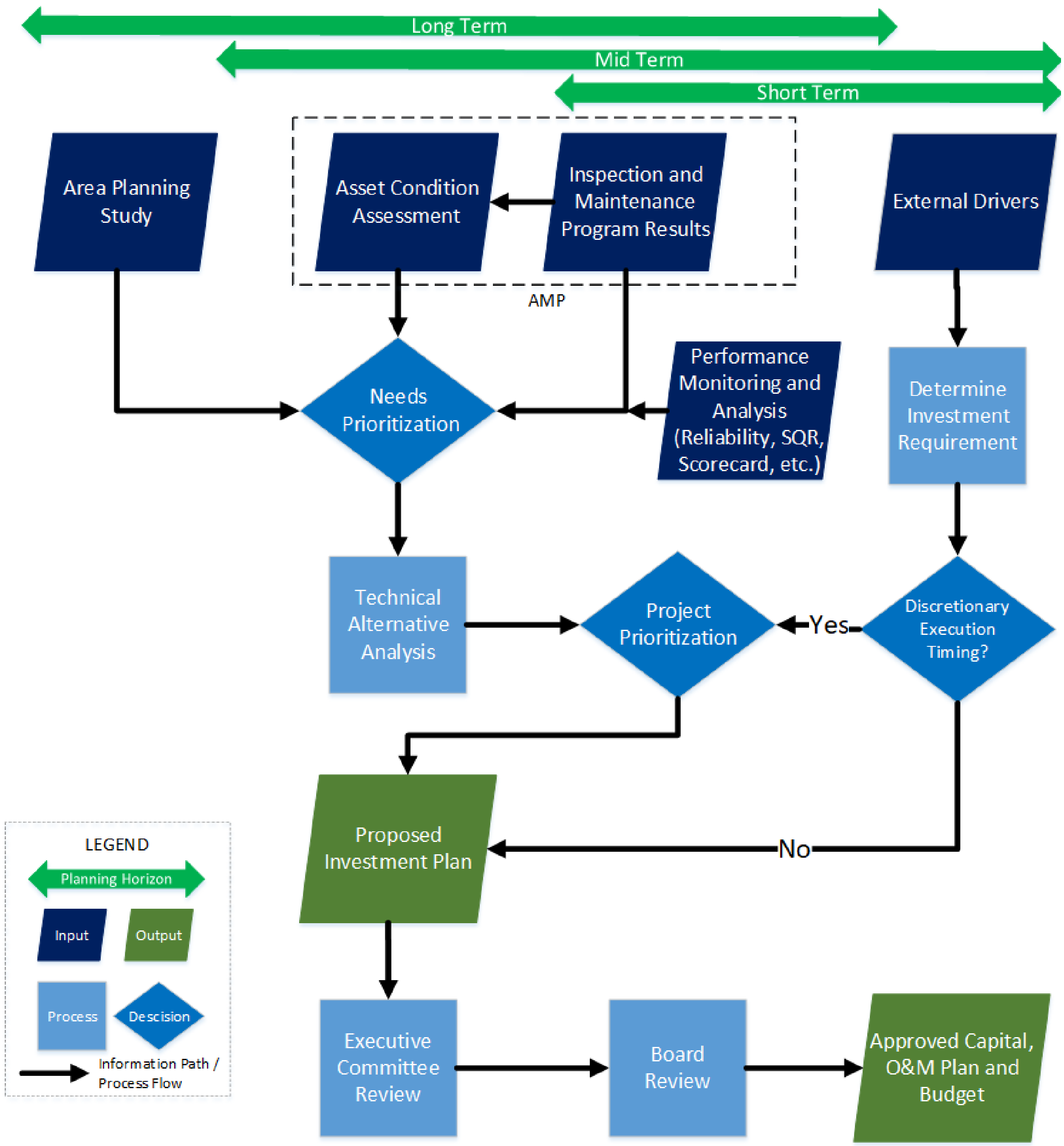
The majority of general plant investments are relatively predictable based on forecasted end of life or obsolescence of fleet, equipment, tools, IT assets, etc. Identified risks and circumstances that could require changes to forecasted investments in this category include:

- Unexpected failure or damage to general plant assets prior to forecasted end of life (e.g. vehicle accidents, weather-related damage to facilities, sudden equipment failure, etc.);
- Emerging cybersecurity risks; and,
- Changes in technology and costs that allow alternative approaches to meet CNPI's identified business needs.

4.2.2 PROCESSES, TOOLS AND METHODS (5.4.1B)

CNPI's system planning process was introduced in Section 3.1, in the context of describing the components of CNPI's AMP. The system planning process flowchart is repeated in Figure 22, and the balance of this section describes the interaction between various inputs and processes used to determine CNPI's capital investment and O&M plans.

Figure 22: System Planning Process



CNPI employs various software and business systems related to the inputs identified in Figure 22, including its SAP ERP software, GIS system, and specialized Engineering Analysis software integrated with its GIS system. SCADA and AMI systems also provide input to load allocation processes for engineering analysis.

CNPI does not employ software systems directly related to the asset management, alternatives analysis or project prioritization processes identified in Figure 22, instead relying on experience planning, engineering and management employees with intimate knowledge of CNPI's system and assets to apply engineering judgment to these processes.

Sources of information that allow CNPI to identify and prioritize investments needs include:

- ACA results and detailed condition/deficiency results produced through inspection, maintenance and testing programs within CNPI's AMP;
- The APS included in Appendix E, which identifies requirements to address asset utilization and contingency risk to allow CNPI to reliably supply forecasted load under a variety of system configurations and contingencies; and,
- Monitoring and analysis of reliability and performance trends, including the performance metrics identified in Section 2.3 of this DSP.

Where more than one technical alternative exists to resolve an identified need, the costs and benefits of each alternative are considered to identify the preferred alternative. Examples of this analysis are provided throughout the APS.

Projects and programs identified through the process described above are combined with externally-driven projects where there is some discretion in timing (e.g. meeting government policy mandates or legal requirements by a future-year deadline). These projects are then assessed for relative priority based on risks and benefits related to safety, reliability, operational efficiency, customer value and preferences, environmental factors, cyber security and other factors as applicable. Projects and programs related to replacing end-of-life assets are generally given higher priority due to impact on safety, reliability and future investment requirements (i.e. avoiding cost inefficiencies related to one-off reactionary replacements due to sudden failure). Wherever possible, opportunities are identified to align end of life asset replacements with solutions to address reliability, contingency and performance issues. The prioritized projects and programs are combined with non-discretionary externally driven projects (primarily System Access) to arrive at a proposed investment plan. CNPI's annual capital and O&M budgets are then finalized following executive and board review.

4.2.2.1 CUSTOMER PREFERENCES FOR INVESTMENT PACING AND PRIORITIZATION

Input from customer engagement activities is incorporated as one of the criteria during the project prioritization step of CNPI's system planning process. In preparing this 2022-2026 DSP, CNPI carried out DSP-specific customer surveys to assess customer priorities, as well as customer support for overall levels of capital investment and the distribution rate increases that would result from those investments. While the majority of customers supported CNPI's proposed level of capital investments in each category, the median level of rate increase supported was slightly lower than the amount resulting from CNPI's proposed investments. Following these DSP engagement surveys, CNPI was able to pace and prioritize its capital investments at a slightly reduced level that addresses identified asset replacement and system performance needs, while keeping rate impacts in line with customer preferences. CNPI also included a lower increase to its tree trimming program in 2022, in line with the levels supported by customer engagement.

4.2.3 REG INVESTMENT PRIORITIZATION (5.4.1C)

While CNPI does not expect significant, if any, customer interest in connecting REG projects, investment prioritization for enabling connection of REG would follow the same process and prioritization criteria specified above.

As described in detail in Section 3.4, CNPI has not experienced any major issues with connection of existing microFIT or small FIT projects to its system and does not expect any issues within the current 5-year plan. As such, no specific projects or programs have been prioritized in consideration of enabling REG connections.

4.2.4 NON-DISTRIBUTION SYSTEM ALTERNATIVES TO RELIEVING SYSTEM CAPACITY (5.4.1D)

CNPI has not identified any projects in the current DSP where implementing non-distribution system alternatives ("non-wires solutions") such as DER or demand response would be the preferred alternative to resolve an identified need. However, the effect of existing embedded generation on feeder loading is incorporated into the APS, such that capacity needs are not being overstated (i.e. load allocation is based on historical net loading, as seen at CNPI's delivery points, and contributions from embedded generation, demand reduction and energy efficiency are not being added back to determine gross load values). CNPI will continue to participate in Regional Planning processes and will monitor OEB consultations and policy developments related to DER to ensure that non-distribution alternatives are appropriately considered in its alternatives analysis process.

4.2.5 SYSTEM MODERNIZATION (5.4.1E)

CNPI has recently implemented a new online customer portal for account management and billing functions. During the selection process, CNPI was cognizant of customer feedback related difficulty using legacy systems for e-billing and accessing historical consumption data. This resulted in CNPI selecting a system that manages these functions through a single interface and provides flexibility to gradually roll out incremental functionality for self-serve options and electronic forms that will be fully integrated with CNPI's CIS system.

From a business system modernization perspective, CNPI has also taken advantage of opportunities to cost-effectively increase the integration between a number of software systems implemented over the past decade. These efforts include automating queries to exchange data between OMS, GIS, AMI, SCADA and CIS systems to improve system analysis, outage response and customer communication processes. CNPI's next round of pole testing in 2021 is also piloting the use of mobile electronic inspection forms that will allow results to be directly uploaded into its GIS system, instead of providing results in a stand-alone database.

From a distribution system perspective, CNPI's ongoing voltage conversion efforts and distribution automation deployments will result in its distribution system evolving to increased use of higher voltage levels and more reliable configurations, which will facilitate future installations of DER and complex loads compared to prior configurations.

4.2.5.1 RATE-FUNDED ACTIVITIES TO DEFER DISTRIBUTION INFRASTRUCTURE (5.4.1F/5.4.1.1)

CNPI is not proposing any rate-funded Conservation and Demand Management (CDM), demand-response, efficiency or storage activities within the forecast period for the purpose of deferring investments in distribution infrastructure. However, CNPI will consider such solutions on a case-by-case basis where implementing one or more of these activities may result in deferring planned capital investments or may address operational or reliability issues.

4.3 CAPITAL EXPENDITURE SUMMARY (5.4.2)

Table 16 below, which reproduces OEB Appendix 2-AB, provides a summary of CNPI's actual capital expenditures for the 2017-2021 historical period compared to the capital expenditure plan presented in its 2017-2021 DSP. Planned capital expenditures for the 2022-2026 forecast period, consistent with the summary provided in Section 4.1.1 are also included for comparison. The remainder of this Section 4.3 provides detailed variance analysis of planned vs. actual capital expenditures over the 2017-2021 historical period. Section 4.4 provides justification for all material programs and projects planned for the 2022-2026 forecast period.

Table 29: OEB Appendix 2-AB Capital Expenditures

CATEGORY	Historical Period (previous plan & actual)								
	2017			2018			2019		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var
	$ '000		%	*$ '000*		%	*$ '000*		%
System Access	1,459	3,128	114.4%	1,098	5,713	420.5%	1,120	3,869	245.6%
System Renewal	4,991	3,310	-33.7%	5,939	7,833	31.9%	5,496	6,863	24.9%
System Service	1,842	2,018	9.6%	1,064	1,588	49.1%	1,505	2,459	63.4%
General Plant	2,016	2,061	2.2%	1,825	2,238	22.6%	1,621	2,251	38.9%
TOTAL EXPENDITURE	**10,307**	**10,517**	**2.0%**	**9,926**	**17,371**	**75.0%**	**9,742**	**15,443**	**58.5%**
Capital Contributions	-550	-1,327	141.3%	-561	-1,812	223.1%	-572	-773	35.0%
Net Capital Expenditures	**9,757**	**9,190**	**-5.8%**	**9,365**	**15,559**	**66.1%**	**9,170**	**14,671**	**60.0%**
System O&M	*4,107*	*3,927*	*-4.4%*	*4,189*	*3,967*	*-5.3%*	*4,273*	*3,980*	*-6.9%*

CATEGORY	Historical Period (previous plan & actual)						Forecast Period (planned)				
	2020			2021			2022	2023	2024	2025	2026
	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	*$ '000*		%	*$ '000*				
System Access	1,144	2,849	149.1%	1,166	1,765	51.3%	1,771	1,718	1,710	1,711	1,711
System Renewal	5,461	9,179	68.1%	7,044	10,747	52.6%	7,259	6,537	7,826	6,865	6,865
System Service	1,179	1,957	66.0%	836	1,855	122.0%	3,305	1,695	1,345	1,295	1,845
General Plant	2,478	1,967	-20.6%	2,074	2,354	13.5%	2,007	1,846	1,851	1,708	1,578
TOTAL EXPENDITURE	**10,261**	**15,953**	**55.5%**	**11,119**	**16,721**	**50.4%**	**14,343**	**11,796**	**12,732**	**11,579**	**11,999**
Capital Contributions	-584	-1,730	196.5%	-595	-900	51.2%	-900	-850	-850	-850	-850
Net Capital Expenditures	**9,677**	**14,222**	**47.0%**	**10,524**	**15,821**	**50.3%**	**13,443**	**10,946**	**11,882**	**10,729**	**11,149**
System O&M	*4,358*	*4,216*	*-3.3%*	*4,445*	*4,147*	*-6.7%*	*4,125*	*4,208*	*4,292*	*4,378*	*4,465*

4.3.1 VARIANCES BY CAPITAL INVESTMENT CATEGORY

The following sections provide variance analysis between actual capital investments (forecast for the 2021 Bridge Year) vs. the 2017-2021 planned investments identified in CNPI's prior DSP.

4.3.1.1 SYSTEM ACCESS

Net System Access investments exceeded CNPI's 2017-2021 plan as summarized in the following table. CNPI's prior DSP did not include any categorization within the System Access category, therefore variances are discussed in the context of the major drivers of overall System Access investments.

Table 30: System Access Historical Period (2017-2021) Variance Summary

System Access	Plan (Net of CIAC)	Actual (Gross)	CIAC	Actual (Net)	Variance
Services		4,602	(1,765)	2,837	
Subdivisions, Condos, Townhouses		5,804	(2,298)	3,506	
Meters		1,571	-	1,571	
Transformers		1,636	-	1,636	
Joint Use & Relocations		3,712	(1,450)	2,262	
Total	**3,124**	**17,325**	**(5,513)**	**11,812**	**8,688**

At the time of filing its previous DSP, CNPI had identified a slight uptick in residential housing activity in 2016 and 2017. Without any certainty on whether this increased activity would continue, CNPI forecasted lower 2018-2021 System Access investment levels that were consistent with recent years, but identified changes in residential development activity as a contingency that would affect its capital investment levels.

Instead of seeing a return to previous levels of housing activity, CNPI experienced a surge of subdivision developments in its Niagara service area over the historical period:

- 2017: 3 new subdivisions with a total of 64 lots
- 2018: 10 new subdivisions with a total of 336 lots
- 2019: 8 new subdivisions with a total of 477 lots
- 2020: 4 new subdivisions with a total of 120 lots

CNPI has also undertaken several system expansions to connect commercial customer in recent years. Housing activity stalled during portions of 2020 and 2021 as a result of pandemic-related restrictions and CNPI has forecasted slightly lower System Access investments for 2021.

The non-discretionary customer connection activity described above, including meters and transformers required to connect new services, comprises $9.6 million (over 80%) of CNPI's System Access investment for the historical period.

The remainder of CNPI's System Access investments relate to joint-use and road relocation activity. In typical years, net investments for these types of projects (if any) range from approximately $100-300k.

- $430k net investment for make-ready work related to a broadband expansion project in the Gananoque area in 2017/2018.
- $430k net investment related to road relocation projects in Gananoque area in 2018.
- $810k for two road relocations projects in the Niagara area in 2018.

The increase in customer-driven and third-party driven investments in this category resulted in higher capital contributions, totaling $5.5 million over the 2017-2021 period, compared to a total of $2.9 million in CNPI's previous DSP.

4.3.1.2 SYSTEM RENEWAL

Net System Renewal investments exceeded CNPI's 2017-2021 plan as summarized in the following table. For major projects and programs included in CNPI's prior DSP, variances are discussed at a project/program level. For the balance of System Renewal investments (i.e. the category total, less the total of material projects outlined in the prior DSP), variances are discussed in the context of various other investment drivers. Discussion of voltage conversion variances from the System Service category are also discussed in this section along with the System Renewal voltage conversion programs since these investments are part of the same overall programs.

Table 31: System Renewal Historical Period (2017-2021) Variance Summary

System Renewal	Plan (Net of CIAC)	Actual (Gross)	CIAC	Actual (Net)	Variance
Voltage Conversion	4,747	10,210	-	10,210	5,463
Targeted Pole Replacement	5,071	5,706	(62)	5,644	573
Distribution System Upgrades and Replacements	10,810	4,416	(323)	4,092	(6,718)
Transformer Replacements		2,756	-	2,756	2,756
North Line Rebuild	1,117	1,382	-	1,382	265
Port Colborne South DS	1,659	3,882	-	3,882	2,223
5/8 Line 34.5kV Distribution Line Rebuild	250	140	-	140	(110)
New FE South DS	1,700	2,748	-	2,748	1,048
Subtotal - Material Projects/Programs from Prior DSP	***25,354***	***31,239***	***(386)***	***30,853***	***5,499***
Station 12 Protection Replacement		269	-	269	
Gananoque Second Supply		156	-	156	
Canal Risers		240	-	240	
EOP Distributed Option		971	-	971	
Fielden Transformer		711	19	730	
Port Colborne TS Rebuild		1,038	(602)	436	
Other / Less Than Materiality		2,013	-	2,013	
Storm Capital Costs		1,297	(4)	1,293	
Subtotal	***3,228***	***6,694***	***(588)***	***6,107***	***2,879***
Total	**28,582**[18]	**37,934**	**(974)**	**36,960**	**8,378**

CNPI's previous DSP identified approximately $8M in combined System Renewal and System Service investments related to voltage conversion for specific 4.8 kV delta sections of its Fort Erie distribution

[18] The total of 2017-2021 Planned System Renewal investments in CNPI's OEB Appendix 2-AB is $28,930,000. One of the 2017 projects (Station 19 DS Protection Upgrade & Arc Flash Hardening: $348k) was identified as System Service in the DSP, but inadvertently include as System Renewal in Appendix 2-AB. Because that project is included the System Service variance analysis below, CNPI has adjusted the System Renewal and System Service planned totals accordingly.

system. Actual investments in voltage conversion projects for the historical period are expected by be $14.9M ($10.2 million under System Renewal plus $4.7M under System Service, with the following explanations for the $6.9M variance:

- The prior DSP identified the QEW North and Ridgeway areas as the primary focus areas, with limited ability to complete conversions in the Fort Erie South and other areas until 2021.
- CNPI reassessed voltage conversion priorities on an ongoing basis, with consideration of updated asset condition data, reliability performance (including increasing issues with ratio bank reliability in certain areas), and contingency risk.
- Accelerating voltage conversion efforts in the QEW North area, while also completing most of the Ridgeway voltage conversion scope, allowed CNPI to better coordinate voltage conversion efforts with asset replacement requirements.
- After completing the majority of its QEW North voltage conversion efforts ahead of schedule, CNPI was able to advance Fort Erie South voltage conversion efforts for 2020 and 2021, better aligning these investments and some outstanding portions of the Ridgeway area with its Fort Erie South substation investment schedule.
- The combination of the changes discussed above will allow an earlier retirement of Station 12, which is the last substation supplying delta-connected load in Fort Erie, reducing system losses and improving contingency response.
- Through a combination of the additional asset replacements carried out in conjunction with voltage conversion programs, and having a distinct program for targeted pole replacements, CNPI was able to offset the $6.9M increase in voltage conversion investments by reducing investments in the Distribution Upgrades and Replacements program by approximately $6.7M (this program addresses smaller distribution line rebuild requirements or asset replacements not covered under voltage conversion or pole replacement programs)

While distribution transformer replacements were not identified as a distinct program within the prior DSP, material investments were made for transformers that were purchased to allow replacement of transformers found to be in poor condition during the accelerated voltage conversion programs as well as during other line rebuilds. The results of CNPI's ACA indicate that the pole-mounted distribution asset class contains the largest percentage of assets in poor or very poor condition. As a result, replacement of poor condition transformers during line rebuilds is an efficient way to improve the overall health-index of this asset class and avoid a future spike in sudden failures.

With respect to substation rebuilds, CNPI planned to construct two new dual-element substations (Fort Erie South and Port Colborne South), at a cost of approximately $1.7 million each. The Fort Erie South DS (Rosehill DS) proceeded generally as planned, with construction initiated in 2020 and completion on schedule for 2021. Following competitive tendering processes, the total cost is expected to be approximately $2.75 million (i.e. approximately $1 million higher than plan).

In Port Colborne, CNPI was unable to secure land for the planned new substation that met requirements for size, proximity to existing feeders, zoning and availability for purchase. Rather than proceed with costly and time-consuming expropriation and re-zoning processes, CNPI revised its Port Colborne investment plans to rebuild the existing Jefferson DS and Catharine DS as separate single-element substations. The combined cost of these substation rebuilds is approximately $3.9 million. While this represents a $2.2 million increase from the planned investment level included in CNPI's prior DSP, the cost of the competitively procured dual-element substation in Fort Erie (i.e. $2.75M) combined with the need for expropriation in order to build the planned substation would have likely resulted in a similar cost increase had CNPI proceeded with its initial plan.

CNPI's 2017-2021 investment plan contained approximately $3.2 million for System Renewal over the 5-year period not identified in the material program/projects section of the prior DSP. This amount generally covers relatively immaterial items such as substation investments in control building components, battery replacements, major equipment spares, and similar items (see other / less than materiality row in Table 31), as well as distinct unplanned projects that arise during the forecast period but don't fit within the scope of standing investment programs (e.g. replacing major equipment after failures). CNPI's actual investments in this area totaled $6.1 million, for a variance of $2.9 million, primarily driven by the following larger unplanned projects:

- $1.3 million in storm damage capital costs, $0.52 million of which relates to a single severe storm in 2019 that was the subject of a z-factor claim (for the O&M portion only) in EB-2020-0008.
- $436k net investment in rebuild and relocation work to accommodate Hydro One's efforts to advance a rebuild of the Port Colborne TS and 115 kV supply to improve reliability in Port Colborne (see Section 2.2.1.3 for additional detail).
- $971k related to initial investments to install a series of distributed padmount transformers in the Gananoque service area as an alternative solution for retiring the end-of-life Gananoque DS. The overall project and related investments in voltage conversion will continue into the forecast period and the selection of this alternative is described in detail in Section 4.4.2.2.4.

4.3.1.3 SYSTEM SERVICE

Net System Service investments exceeded CNPI's 2017-2021 plan as summarized in the following table. For major projects and programs included in CNPI's prior DSP, variances are discussed at a project/program level. For the balance of System Service investments (i.e. the category total, less the total of material projects outlined in the prior DSP), variances are discussed in the context of various other investment drivers.

Table 32: System Service Historical Period (2017-2021) Variance Summary

System Service	Plan (Net of CIAC)	Actual (Gross)	CIAC	Actual (Net)	Variance
Voltage Conversion	3,327	4,709	-	4,709	1,382
Distribution Automation and Reliability	1,383	2,094	-	2,094	711
EOP Main Substation - Delta to Wye	750	656	-	656	(94)
Station 19 Projects	348	560	-	560	212
Killaly DS	410	-	-	-	(410)
Subtotal – Material Projects/Programs from Prior DSP	***6,218***	***8,018***	***-***	***8,018***	***1,800***
Distribution System Upgrades and Replacements		488	(23)	465	
Station 12 Protections		515	-	515	
Stevensville DS		175	-	175	
Wildlife Protection		285	-	285	
Other / Less than Materiality		395	-	395	
Subtotal	***556***	***1,858***	***(23)***	***1,835***	***1,279***
Total	**6,774**[19]	**9,876**	**(23)**	**9,853**	**3,079**

The majority of the $1.8M total System Service variance related to material projects from CNPI's prior DSP is due to additional investments of $1.4M for voltage conversion, with variance explanations addressed with System Renewal voltage conversion program in the preceding section. CNPI has also increased investments in recent years related to implementation of distribution automation schemes and installation of fault indicators to improve outage restoration efforts.

CNPI's prior DSP identified a $410k project to improve supply redundancy and replace protective devices switchgear in the Killaly DS. As described in the APS, recent failures have led to repairs that have replaced supply cables and primary protective devices, partially completing the scope of the previously planned project. Further ACA results have identified the power transformers at Killaly as being in poor condition. As a result, CNPI has deferred further investment in low voltage switchgear replacement and other station upgrades. Section 4.4.2.3.3 describes a placeholder project for these investments in the

[19] Adjusted to reclassify the Plan amount for Station 19 Projects – see previous footnote.

forecast period, pending further assessment on project alternatives such as increased voltage conversion in the East of Welland Canal area of Port Colborne.

CNPI's 2017-2021 investment plan contained $556k for System Service over the 5-year period not identified in the material program/projects section of the prior DSP. This amount generally covers relatively immaterial items such as upgrading individual protection devices, switches or controls for reliability reasons, installing new equipment to improve reliability or power quality, and advanced engineering for reliability improvement projects. CNPI's actual investments in this area totaled $860k (Upgrades/Replacements and Other/Less than Materiality rows in Table 32), for a variance of $300k. The remaining variance of approximately $1 million relates to the following projects:

- $515k for replacement of end of life protection equipment in Station 12 in 2018/2019.
- $285k for installation of wildlife guards in 2020 and 2021 to reduce animal-caused outages.
- $175k for preliminary work related to the Stevensville DS rebuild planned for 2022 (see Section 4.4.2.3.2 for justification related to the 2022 project).

4.3.1.4 GENERAL PLANT

Net General Plant investments exceeded CNPI's 2017-2021 plan as summarized in the following table. For major projects and programs included in CNPI's prior DSP, variances are discussed at a project/program level. For the balance of General Plant investments (i.e. the category total, less the total of material projects outlined in the prior DSP), variances are discussed in the context of various other investment drivers.

Table 33: General Plant Historical Period (2017-2021) Variance Summary

General Plant	Plan (Net of CIAC)	Actual (Gross)	CIAC	Actual (Net)	Variance
IT Software	5,278	4,769	-	4,769	(509)
IT Hardware	1,404	1,272	-	1,272	(132)
Fleet	1,828	2,638	--	2,638	810
New FE South DS	250	175	-	175	(75)
Subtotal – Material Projects/Programs from Prior DSP	***8,760***	***8,855***	***-***	***8,855***	***95***
Facilities, Yards, Land		891	(13)	878	
Radio Tower Replacement		234	-	234	
EOP Service Centre		165	-	165	
Other / Less than Materiality		727	(20)	707	
Subtotal - Other	***1,254***	***2,017***	***(33)***	***1,984***	***730***
Total	**10,014**	**10,871**	**(33)**	**10,839**	**825**

Overall variances in the General Plant category are all below CNPI's rate base materiality threshold, with higher investments in fleet replacements (based on replacement criteria for each class of equipment) and facilities renovations offset by reductions in IT capital investments.

4.4 JUSTIFYING CAPITAL EXPENDITURES (5.4.3)

This section provides the necessary data, information, and analyses to support the 2022-2026 capital investments proposed in this DSP.

4.4.1 OVERALL PLAN (5.4.3.1)

CNPI has arrived at an overall investment plan that balances the following drivers:

- Non-discretionary investments driven by customer connection requests and third-party requirements (System Access)
- Asset end-of-life considerations, based on the results of its ACA, its asset management objectives, and the outcome of area planning studies (System Renewal)
- Investments to improve system reliability and reduce contingency risk based on the outcome of area planning studies, and aligned where practical with end-of-life considerations (System Service)
- Investments to support operational efficiency and day-to-day operation, maintenance, customer service and administrative functions (General Plant)

The identified needs and preferences of CNPI's customers, as determined through customer engagement activities, was considered in prioritizing investments within each category, as well as in pacing the overall annual level of investment considering rate impacts.

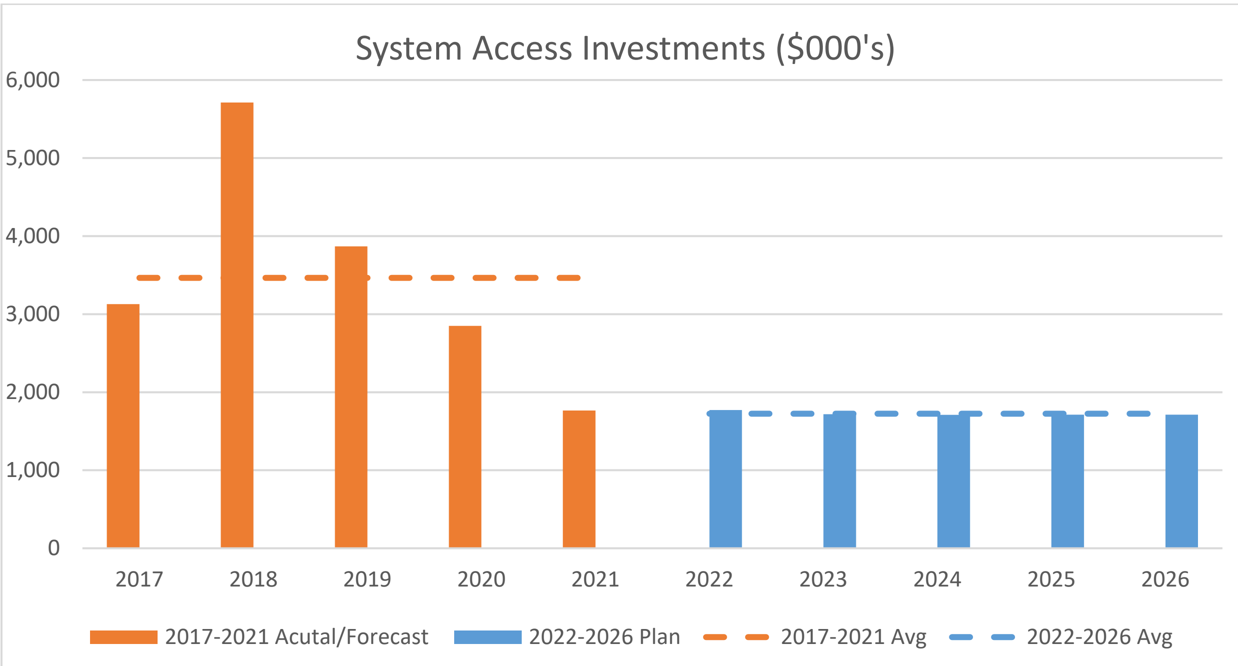
For each capital investment category, the sections below provide support for the overall level of investment included in this DSP by summarizing the following information listed in Section 5.4.3.1 of the Filing Requirements:

- Comparative expenditures by category over the historical period.
- The forecast impact of system investment on system O&M costs.
- The drivers of investments by category, including historical trend and expected evolution of each driver over the forecast period.

4.4.1.1 SYSTEM ACCESS

Figure 23 compares annual System Access investments over the historical and forecast periods:

Figure 23: 2017-2026 System Access Investments

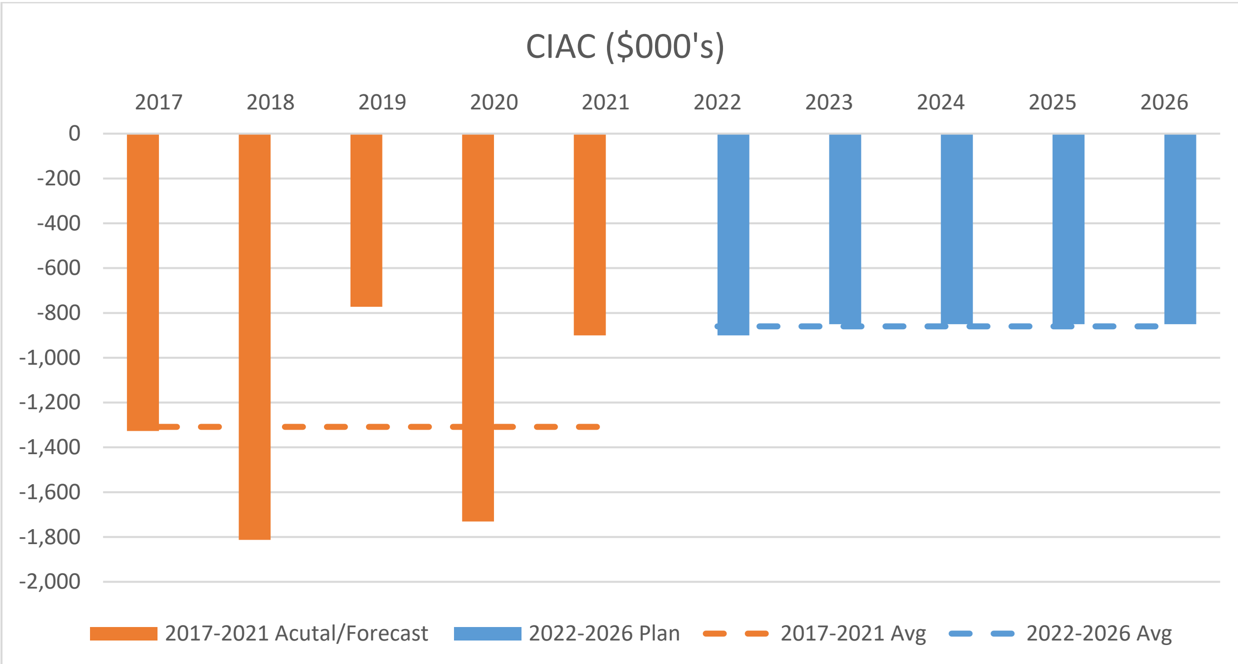


CNPI has planned for gross System Access levels of approximately $1.7 million over the forecast period. This represents a significant decrease compared to the historical period, due to lack of identified/committed housing developments and uncertainty related to the timing of infrastructure projects post-pandemic. CNPI has identified fluctuations in housing activity and infrastructure spending as key areas of uncertainty that could affect actual System Access investments. Based on its experience in managing surges in activity in the historical period, CNPI is confident that it can ramp resources up or down as required to meeting fluctuating demand for this type of work.

System Access investments generally have minimal impact on O&M, in some cases adding to the overall length of line that must be inspected and maintained.

CNPI has also forecasted lower average levels of CIAC for the forecast period, as illustrated in Figure 24. Any changes in investment levels will likely result in changes to CIAC offsets.

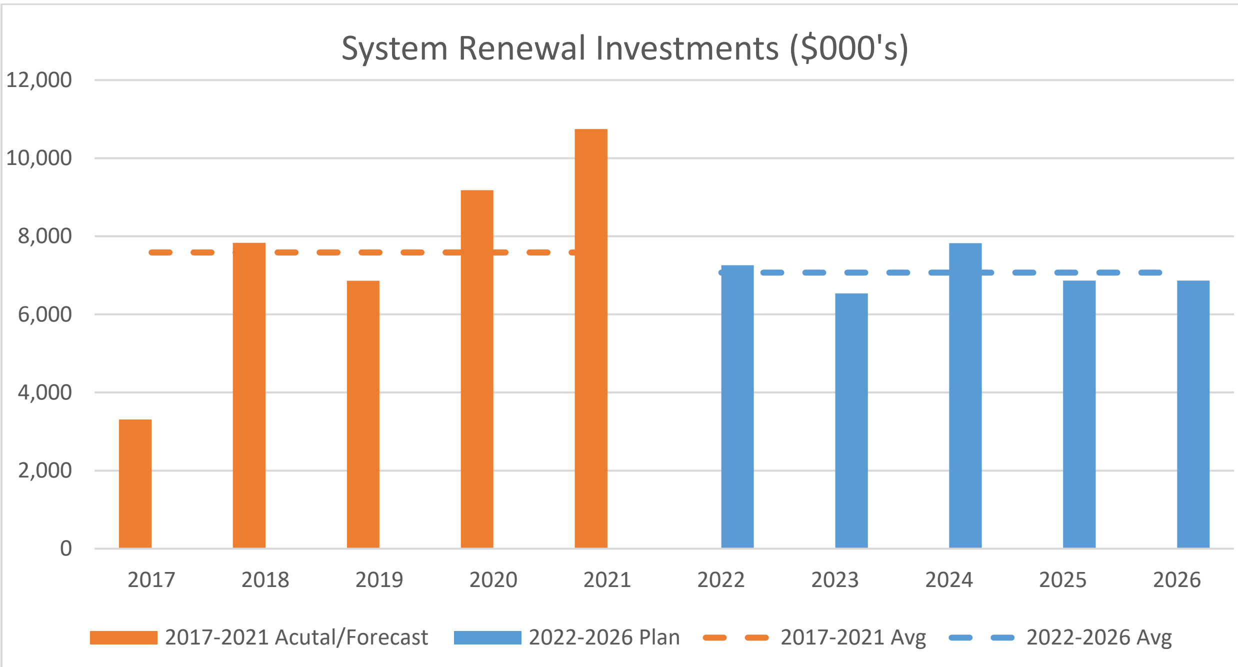
Figure 24: 2017-2026 Contributions in Aid of Construction (CIAC)



4.4.1.2 SYSTEM RENEWAL

Figure 25 compares annual System Renewal investments over the historical and forecast periods:

Figure 25: 2017-2026 System Renewal Investments



Planned System Renewal investments over the forecast period are approximately 7% lower than the historical period average. This investment level will allow CNPI to continue recent progress in addressing asset end-of-life replacement requirements at a pace that allows synergies with voltage conversion programs and system reconfigurations to improve reliability, contingency planning and system performance.

The results of CNPI's ACA confirm that all distribution line asset classes other than reclosers have more than 50% of assets in fair or worse condition, indicating that maintaining recent replacement levels is prudent. Conversely, substation assets are generally in better condition and fewer substation projects accounts for the decreasing trend in System Renewal investments.

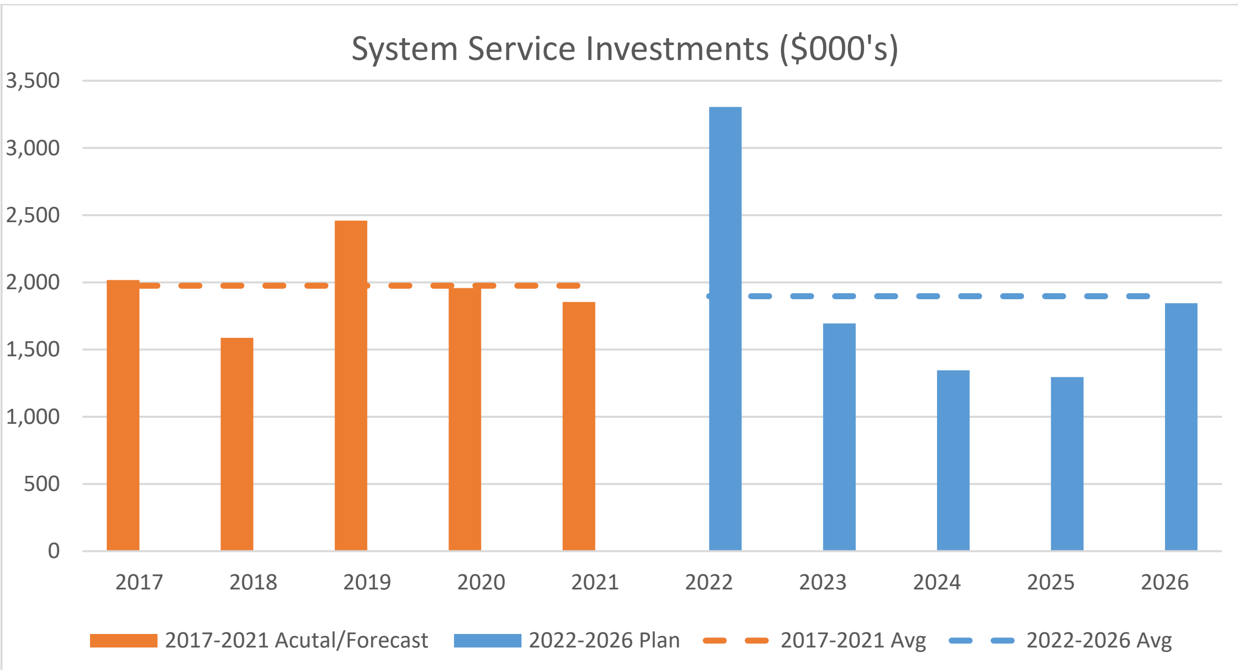
System renewal investments generally result in downward pressure on O&M and other costs through:

- Reducing the costs associated with system losses that are ultimately paid by customers
- Reducing inefficiencies associated with reactionary replacement (higher per-unit costs, like-for-like replacements may impede longer-term system plans, etc.)
- Renewed assets generally require less maintenance that the assets being replaced.

4.4.1.3 SYSTEM SERVICE

Figure 26 compares annual System Service investments over the historical and forecast periods:

Figure 26: 2017-2026 System Service Investments



Planned System Renewal investments over the forecast period are approximately 4% lower than the historical period average. Aside from a new substation in 2022 that fit the criteria for System Service rather than System Renewal, the trend in System Service investments is generally declining over the forecast period. The 2026 increase relates to a placeholder project to increase redundancy at Killaly DS, pending further assessment of voltage conversion alternatives.

CNPI expects to monitor reliability trends and reprioritize System Service investments over the forecast period if required.

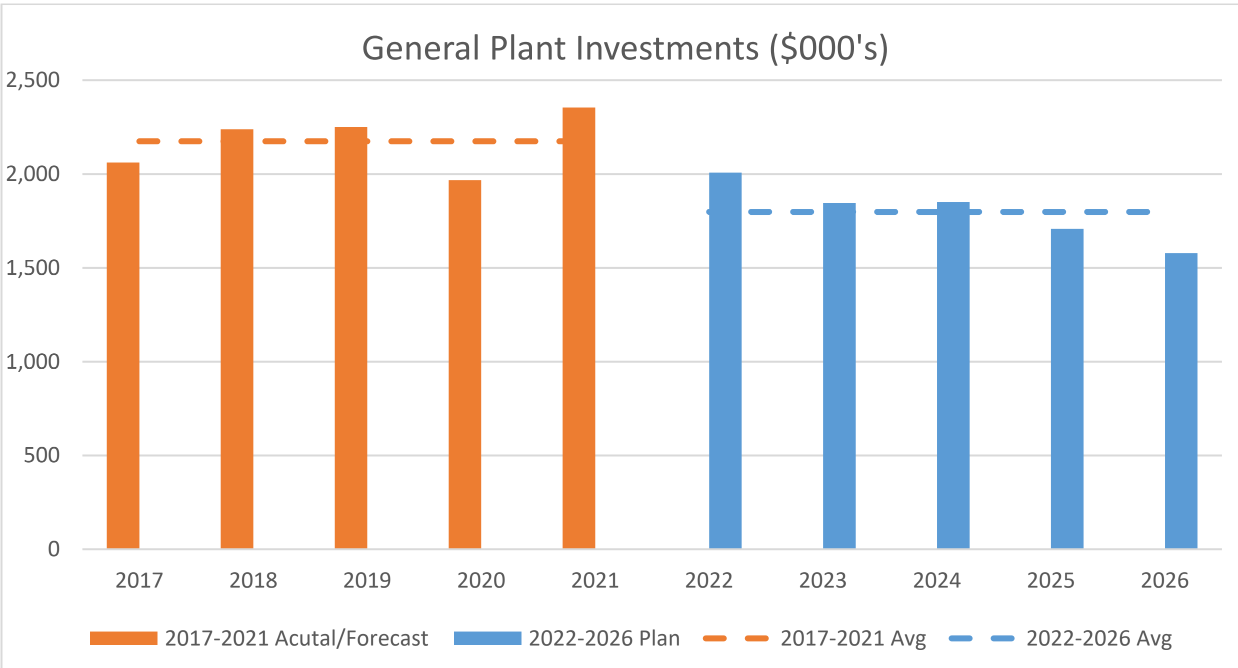
System renewal investments generally result in downward pressure on O&M and other costs through:

- Reducing the costs associated with system losses that are ultimately paid by customers
- Automating restoration to avoid mobilizing crews
- Increasing efficiency of restoration efforts by better directing crews to the cause of sustained outages

4.4.1.4 GENERAL PLANT

Figure 27 compares annual System Service investments over the historical and forecast periods:

Figure 27: 2017-2026 General Plant Investments



Planned General Plant investments over the forecast period are approximately 17% lower than the historical period average. The declining trend is primarily related to:

- A decrease in projected fleet replacement requirements over the forecast period, which could vary slightly if operating and maintenance costs warrant early replacement of specific vehicles.
- A declining trend over time for IT investments based on increasing use of cloud-based solutions and other advancements in technology.

The majority of General Plant investments are made to replace or upgrade end-of-life assets that are obsolete or not performing efficiently. As such, most investments will either be cost-neutral from an O&M perspective (e.g. laptop replacements), or will result in moderate efficiency gains (e.g. increased customer self-serve options).

Certain General Plant investment alternatives, such as migrating to cloud-based solutions may result in upward pressure on OM&A costs, depending on the evolution of accounting standards and regulatory policy related to these types of investments. CNPI intends to evaluate such alternatives in consideration of overall lifecycle costs as well as implications to performance and cybersecurity.

4.4.2 MATERIAL INVESTMENTS (5.4.3.2 INCL ALL SUBSECTIONS)

The focus of this section is to support the material projects and programs comprising CNPI's 2022 to 2026 capital investments.

The majority of CNPI's capital expenditures over the forecast period consist of multi-year programs or budget items where individual projects or areas of focus within these programs shifts over time. CNPI is therefore providing the detail required in Section 5.4.3.2 of the Filing Requirements at a program level for most budget items, with an additional annual breakdown of areas of focus within each program where applicable. For certain distinct projects, CNPI is providing details at the project level under separate headings. Tables within each investment category indicate which programs/projects exceed CNPI's materiality threshold,[20] projects that are distinct for other reasons,[21] and programs/projects that fall below CNPI's materiality threshold.[22]

In the remaining sections of this DSP, CNPI has combined the following items from Section 5.4.3.2 of the Filing Requirements under a single heading for each material program/project for ease of review:

- 5.4.3.2.A – General Information on the Project/Activity
- 5.4.3.2.B – Evaluation Criteria and Information Requirements for Each Project/Activity
- 5.4.3.2.C – Category-Specific Requirements for Each Project/Activity

4.4.2.1 SYSTEM ACCESS

The following table summarizes CNPI's planned System Access investments over the forecast period.

Table 34: System Access Investment Summary for the Forecast Period (2022-2026)

SA Project/Program	2022	2023	2024	2025	2026	Total	Materiality
Service Connections (Incl Subdivisions)	1,000	979	979	979	979	4,915	**> Threshold**
Meters	393	359	351	352	352	1,807	**> Threshold**
Transformers - SA	80	80	80	80	80	400	< Threshold
Relocations, Joint-Use	299	300	300	300	300	1,500	**> Threshold**
Total	**1,771**	**1,718**	**1,710**	**1,711**	**1,711**	**8,621**	

[20] CNPI's revenue requirement materiality threshold is identified as $100,000 in Exhibit 1. In consideration of CNPI's proposed Weighted Average Cost of Capital of 5.58% (see Exhibit 5), 2022-2026 capital investments of $100,000 / 0.0558 = $1.79 million (rounded) or more will lead to future revenue requirement impacts of $100,000 or more.

[21] In accordance with Section 5.4.3.2 of the Filing Requirements, CNPI has provided justification for programs/project with unique characteristics or that diverge from prior trends, even if total investments are below the materiality threshold.

[22] Programs/projects that are neither distinct, nor material are listed in these tables in order to reconcile the category totals to OEB Appendix 2-AB, however detailed descriptions are not provided in this section of the DSP.

4.4.2.1.1 SA - SERVICES

General Information on the Project/Program

This program includes all costs for the installation and replacement of CNPI plant that is driven by customer requests for new services or service upgrades. Total investments over the 2022-2026 period are planned at approximately $1 million per year, for a total of $4.9 million. Individual customer-driven projects range from connecting of upgrading standard residential services that lie along CNPI's existing distribution lines to expansions and upgrades required to connect larger commercial/industrial customers.

This program also includes costs related to system expansions and upgrades required to connect new subdivision developments or multi-unit properties.

Evaluation Criteria and Information Requirements for Each Project/Program

1. Efficiency, Customer Value, Reliability

a. The primary driver of this activity is customer service requests. This program allows CNPI to satisfy its planning objective of meeting the needs of its customers, as well as meeting regulatory obligations under the DSC.
b. CNPI is a member of the Utilities Standard Form (USF) and uses USF standards similar to the majority of LDC's in Ontario. The application of USF standardized framing and material used in any modification to CNPI's system satisfies the regulatory requirements and incorporates industry best practices applicable to this type of work. CNPI also incorporates changes in load density resulting from large customer connections or subdivision developments into its area planning studies.
c. This activity is considered non-discretionary, as there are regulatory obligations to process customer service requests in a timely manner. This program includes lower levels of annual investment over the forecast period as compared to recent years due to uncertainty in future housing, though CNPI is prepared to adjust resourcing as required to meet actual levels of requests.
d. Given the regulatory requirements to process these requests, and the requirements of Ontario Regulation 22/04 in relation to the new or modified connections to CNPI's system, few alternatives exist for this activity. For each individual connection however, CNPI does consider whether the connection or upgrade can be accommodated with a minimal scope of work (e.g. connection to existing secondary bus without anchoring or pole changes), while meeting the applicable safety requirements, in order to better align asset replacements with condition-based end of life considerations.

2. Safety

The design and construction of new or modified service connections is completed in accordance with USF Standards to meet the requirements of Ontario Regulation 22/04 and to ensure that no undue safety hazards exist.

3. Cyber Security, Privacy
Customer connections requests are managed in accordance with relevant privacy legislation.

4. Co-ordination, Interoperability
CNPI involves municipalities, road authorities and other agencies in the design review and approval process as required. This ensures coordinated planning with third parties in relation to road activities, other utilities and regulatory concerns. CNPI also considers customer and load growth trends in determining load forecasts for regional planning activities.

5. Environmental Benefits
CNPI works with customers and developers to promote awareness of incentive programs related to energy efficiency for new building construction and retrofits.

6. Conservation and Demand Management to Defer Infrastructure Projects
Service connection requests typically add load to CNPI's system, potentially increasing the need for future additional capacity and reliability-based investments. As described above, CNPI promotes energy efficiency during new construction, recognizing that investments are generally more practical and cost-effective at this stage as compared to future retrofits.

Category-Specific Requirements for Each Project/Program

The projects within this activity relate mostly to individual new or modified connections to residential dwellings or commercial buildings. Once requests are received and customers have met certain obligations, the timing of completing these connections is prescribed by the DSC and CNPI has little control over the timing of specific activities.

CNPI does however make efforts in several areas to control costs and to build efficiencies into the overall design and construction process:

- Online mapping tools, as well as databases of asset and property information are reviewed in the office in advance of site visits to determine reasonable connection options.
- Where practical, site visits with customers/contractors are grouped by area to minimize travel time and costs.
- For each service request, technicians identify whether any minimal scope connection options exist that will both meet the customer's requirements and the requirements of Ontario Regulation 22/04.
- For connections where minimal scope options are not available, opportunities to incorporate efficiencies are considered (e.g. correcting nearby deficiencies to take advantage of line crew and equipment mobilization).

4.4.2.1.2 SA - METERS

General Information on the Project/Program

This program includes costs related to the purchase of revenue meters, instrument transformers and associated equipment required for complete metering installations, as well as labour costs related to the design, installation and commissioning of new complex meter installations. Total investments over the 2022-2026 period are planned at approximately $350-400k per year, for a total of $1.8 million.

Meter installation and replacement requirements generally relate to new service connections and upgrades or replacing end-of-life metering equipment.

Evaluation Criteria and Information Requirements for Each Project/Program

1. Efficiency, Customer Value, Reliability

a. The main driver of the program is non-discretionary customer connection requests, with asset failure or condition assessment contribution to a smaller portion of the overall effort.
b. Advancements in metering technology and capability in response to government and OEB mandates have allowed CNPI to obtain increasingly granular system loading information and operational insights. CNPI will continue integrating and leveraging these data streams into its business systems to improve system planning processes and operational processes such as outage restoration.
c. This program is generally non-discretionary based on Measurement Canada and DSC requirements.
d. Alternatives for metering technologies were evaluated during Smart Meter and MIST meter deployments in prior years. Alternatives for ongoing smart meter purchases are limited based on the system and technology deployed during CNPI's initial Advanced Metering Infrastructure ("AMI") deployment project, though CNPI regularly monitors any changes to the available meter types and technologies from its AMI vendor. For MIST meter installations, which are much smaller in number, CNPI balances standardizing on equipment and designs with monitoring advancements in metering and communications technology.

2. Safety

All metering equipment and metering installations are designed in compliance with Measurement Canada, Ontario Electrical Safety Code and Ontario Regulation 22/04 requirements, as applicable. End-of-life replacement considerations include the extent to which the overall condition of metering assets presents a risk to worker and public safety.

3. Cyber Security, Privacy

CNPI's business systems and communications equipment related to transmitting, storing and accessing metering and billing data include encryption and access controls designed to prevent unauthorized data access. Any wired or wireless communication between meters and other operational technology utilize private network communication exclusively, and activity on these networks is monitored by the company's Managed Security Services Provider ("MSSP").

4. ***Co-ordination, Interoperability***
CNPI's AMI system was procured in partnership with neighbouring utilities in order to achieve cost efficiencies and superior communication coverage as compared to stand-alone solutions. The AMI system continues to be operated in this manner through a long-term service contract between the AMI vendor and multiple LDC's. Investments in additional or replacement metering equipment continue to leverage the initial AMI system deployment.

5. ***Environmental Benefits***
Investments in metering equipment have little direct environmental impact, apart from supporting analysis for CDM opportunities as discussed below.

6. ***Conservation and Demand Management to Defer Infrastructure Projects***
Prior deployments of AMI technology (smart metering) and MIST metering have resulted in hourly consumption data being available for all accounts. This data can support analysis for CDM and energy efficiency projects. Planned investments in new meter installations and meter replacements will use technology that is consistent with these prior deployments and provides the same level of increased data granularity.

Category-Specific Requirements for Each Project/Program

Investments in metering equipment for new services relate directly to the level of customer-driven service work discussed in the previous section. These investments are non-discretionary.

Investments in metering equipment to support end-of-life replacements depend on the number of deficiencies identified during inspection and reverification requirements.

In both cases, CNPI maintains inventory levels that consider the types and quantities of equipment installed, and typical lead time to order additional equipment from suppliers. This results in CNPI being able to issue most metering equipment from inventory to avoid time delays for customer connections or end of life replacements. It also allows CNPI to order metering equipment in quantities that optimize delivery costs.

4.4.2.1.3 SA – LINES (RELOCATIONS, JOINT-USE)

General Information on the Project/Program

This program includes all costs for relocation of, or modifications to CNPI plant that is driven by third-party requests for road relocations/widening, or changes to joint-use attachments. Cost responsibility between CNPI and the requesting party is defined through legislation and joint-use agreements. Total investments over the 2022-2026 period are planned at approximately $300k per year, for a total of $1.5 million.

Evaluation Criteria and Information Requirements for Each Project/Program

1. Efficiency, Customer Value, Reliability

a. The primary driver of this activity is requests from telecommunication companies and road authorities that must be completed in accordance with legislated requirements and joint-use agreements.
b. CNPI is a member of the Utilities Standard Form (USF) and uses USF standards similar to the majority of LDC's in Ontario. The application of USF standardized framing and material used in any modification to CNPI's system satisfies the regulatory requirements and incorporates industry best practices applicable to this type of work.
c. This activity is considered non-discretionary, as there are regulatory obligations to address relocation requests and joint-use make ready work in a timely manner. This program includes lower levels of annual investment over the forecast period as compared to recent years due to uncertainty in future housing, though CNPI is prepared to adjust resourcing as required to meet actual levels of requests.
d. Given the regulatory requirements to process these requests, and the requirements of Ontario Regulation 22/04 in relation to the new or modified connections to CNPI's system, few alternatives exist for this activity.

2. Safety

The design and construction of new or modified service connections is completed in accordance with USF Standards to meet the requirements of Ontario Regulation 22/04 and to ensure that no undue safety hazards exist.

3. Cyber Security, Privacy

Third-party requests are managed in accordance with relevant privacy legislation and the confidentiality provisions of any applicable contractual agreements.

4. Co-ordination, Interoperability

CNPI meets regularly with its municipalities, road authorities and other agencies to coordinate future investment plans and identify opportunities for synergies. CNPI is also actively monitoring regulatory developments related to the *Building Broadband Faster Act, 2021*, in order to determine regulatory policy changes might support improved coordination between its distribution system planning efforts and the broadband deployment planning of telecommunication companies.

5. Environmental Benefits

N/A.

6. Conservation and Demand Management to Defer Infrastructure Projects

N/A.

Category-Specific Requirements for Each Project/Program

The projects within this activity relate to requirements to relocate or upgrade CNPI's distribution line assets to meet the needs of road authorities or joint-use tenants. Once requests are received and certain obligations have been met, the timing for completing these activities is relatively non-discretionary.

CNPI does however make efforts in several areas to control costs and to build efficiencies into the overall design and construction process:

- Online mapping tools, as well as databases of asset and property information are reviewed in the office in advance of site visits to determine reasonable connection options.
- Technicians may identify minimal scope connection options that will both meet the needs of a joint-use tenant and the requirements of Ontario Regulation 22/04, without requiring pole replacements or line rebuilds.

4.4.2.2 SYSTEM RENEWAL

The following table summarizes CNPI's planned System Renewal investments over the forecast period.

Table 35: System Renewal Investment Summary for the Forecast Period (2022-2026)

SR Project/Program	2022	2023	2024	2025	2026	Total	Materiality
Lines							
Voltage Conversion (SR)	2,296	3,250	2,550	2,750	2,750	**13,596**	**> Threshold**
Line Rebuilds/Upgrades/Replacements (SR)	3,197	2,462	2,741	3,357	3,357	**15,114**	**> Threshold**
Stations							
Station 12 / Oakes DS	0	175	1,800	-	-	**1,975**	**> Threshold**
Port Colborne TS Rebuild	176	-	-	-	-	**176**	< Threshold
Gananoque Distributed Supply	300	-	-	-	-	**300**	**Unique Characteristics**
Sherkston DS Transformer	300	-	-	-	-	**300**	< Threshold
Other							
Transformers - SR	612	560	565	568	568	**2,873**	**> Threshold**
Other	379	90	170	190	190	**1,019**	< Threshold
Total	**7,259**	**6,537**	**7,826**	**6,865**	**6,865**	**35,352**	

4.4.2.2.1 SR – VOLTAGE CONVERSION

General Information on the Project/Program

CNPI's voltage conversion program is an ongoing initiative to convert lower voltage and delta-connected systems to higher voltage wye-connected systems. Historical voltage conversion efforts have largely focused on delta-connected systems in Fort Erie and Gananoque due to the increased safety and reliability concerns associated with delta-connected systems.

The current status of CNPI's existing distribution systems, including the extent that various voltage levels are in use is discussed extensively in Section 2 of CNPI's AMP, included as Appendix A. CNPI's APS, included as Appendix E, provides detail on how voltage conversion efforts in progress affect contingency planning, as well as how future voltage conversion efforts can provide alternative solutions to other investments to address substation end of life considerations.

The System Renewal portion of voltage conversion investments over the forecast period relates to voltage conversion activity that is aligned with asset end of life replacements. In cases where existing distribution lines can be converted with minimal scope, the investments are included in the System Service category. Total System Renewal investments in voltage conversion over the 2022-2026 period are planned at approximately $2.7 million per year, for a total of $13.6 million. This represents an increase from $10.2 million in investment over the historical period, reflecting increased emphasis on line rebuilds and associated voltage conversion efforts as substation investments ramp down. Primary areas in which CNPI's plans to focus its voltage conversion efforts over the forecast period include:

- Remaining 4.8 kV delta to 8.3 kV wye conversions in the Fort Erie South area, aligned recent construction of the Rosehill DS and a goal of retiring Station 12.
- 4.16 kV to 8.3 kV conversions in the Stevensville area, aligned with planned construction of a new Stevensville DS as part of CNPI's overall substation strategy for Fort Erie.
- 4.16 kV to 27.6 kV conversions in Gananoque, with a target of sufficiently offloading the 4.16 kV system to allow the Gananoque distributed substation solution to proceed as an alternative to a larger substation rebuild project.
- 4.16 kV to 27.6 kV conversions in the East of Welland Canal section of Port Colborne, aligned with asset end of life considerations to the extent practical to reduce exposure related to Killaly DS contingencies and allow alternatives to future substation investments in this area.

Evaluation Criteria and Information Requirements for Each Project/Program

1. Efficiency, Customer Value, Reliability

a. The main drivers of the voltage conversion programs are a combination of asset end of life and system performance. Voltage conversion programs are planned strategically to maximize overlap with distribution line and substation end of life replacements that would otherwise be required, with the conversion to a higher voltage level offering increased system capacity, reduced system losses, and improved power quality.
b. Voltage conversion programs will modernize CNPI's distribution systems to be able to more efficiently connected evolving loads and distributed energy resources. These programs will also improve contingency options as voltage levels are increasingly standardized within each service area.
c. The majority of CNPI's System Renewal over the 2022-2026 forecast period are either part of an integrated voltage conversion and substation rebuild/replacement strategy. Fort Erie South and Gananoque voltage conversion and substation projects are generally of a higher overall priority within this program due to the safety and reliability risks associated with the Fort Erie 4.8 kV delta system and the urgent requirement to retire the Gananoque DS. Port Colborne voltage conversion plans are important from a reliability perspective, though the specific pacing and priority for this area compared to other areas within the 5-year plan may be adjusted pending the results of pole testing being completed in 2021.
d. Section 5 of CNPI's APS, included as Appendix E, provides detailed alternative analysis for various voltage conversion and system configuration options in each of the areas where voltage conversion work is planned over the 2022-2026 period.

2. ***Safety***

   From a public safety perspective, delta to wye conversions will significantly reduce the risk of feeders remaining energized for downed conductors arising from the difficulty in detecting single-phase faults without a ground reference. From a worker safety perspective

   The design and construction of line rebuilds and associated voltage conversion activity is completed in accordance with USF Standards to meet the requirements of Ontario Regulation 22/04 and to ensure that no undue safety hazards exist.

3. ***Cyber Security, Privacy***

   N/A.

4. ***Co-ordination, Interoperability***

   CNPI meets regularly with its municipalities, road authorities and other agencies to coordinate future investment plans and identify opportunities for synergies. CNPI is also actively monitoring regulatory developments related to the *Building Broadband Faster Act, 2021*, in order to determine regulatory policy changes might support improved coordination between its distribution system planning efforts and the broadband deployment planning of telecommunication companies.

5. ***Environmental Benefits***

   Higher operating voltage will inherently reduce system losses, improving the overall efficiency of CNPI's distribution system.

6. ***Conservation and Demand Management to Defer Infrastructure Projects***

   Considering that voltage conversion programs are strategically aligned with asset replacements for end of life and system performance issues, rather than capacity requirements, CDM projects would not result in any deferral of these investments.

Category-Specific Requirements for Each Project/Program

As discussed above, a high priority is assigned to voltage conversion programs due to the opportunity associated with aligning these investments with a large amount of distribution line and substation rebuild activity that would otherwise be required. Substation projects to support voltage conversion efforts during the historical period have included replacement or retirement of substation assets in poor overall condition, with focus shifting towards increased levels of voltage conversion aligned with line rebuilds during the forecast period.

CNPI's ACA results, which are summarized in Section 3.2.3, indicate that ratio banks, wood poles and distribution transformer asset classes all have more than 50% of assets in very poor to fair condition. Ongoing voltage conversion programs will result in a number of ratio banks being eliminated over time, as well as replacement of a substantial number of poles and transformers. CNPI therefore expects these efforts to result in improved asset health indices for these asset classes by the end of the forecast period.

4.4.2.2.2 SR – LINE REBUILDS/UPGRADES/REPLACEMENTS

General Information on the Project/Program

CNPI's line rebuild/upgrade/replacement program addresses sustaining replacement of end of life distribution line assets that are not part of the voltage conversion program described above. The goal of these investments is to replace distribution line assets (primarily poles and overhead conductor) on a proactive basis aligned with asset end of life, but prior to actual failure. Investments included line section rebuilds where the majority of assets on a given section of line are at or near end of life, as well as targeted replacement of poles and other assets where test results of visual inspections identify critical deficiencies related to specific assets.

Total System Renewal investments in voltage conversion over the 2022-2026 period are planned at approximately $3 million per year, for a total of $15 million. This represents an increase from $12 million in investment over the historical period, reflecting increased emphasis on line rebuilds as substation investments ramp down.

Evaluation Criteria and Information Requirements for Each Project/Program

1. Efficiency, Customer Value, Reliability

a. The primary driver of this program is the planned and sustainable replacement of end of life poles. Secondary drivers are maintaining reliability, optimizing the overall lifecycle costs associated with poles, as well as improved system performance. This program is based on the fundamental objective of CNPI's AMP, which is "to prudently and efficiently manage the planning and engineering, design, addition, inspection and maintenance, replacement, and retirement of all distribution assets in a sustainable manner that maximizes safety and customer reliability, while optimizing asset lifecycle costs." CNPI's asset register and the results of cyclical feeder inspections and third-party testing programs are the primary sources of information driving this program.
b. CNPI is a member of USF and uses USF standards similar to the majority of LDC's in Ontario. The application of USF standardized framing and material used in line rebuild projects satisfies the regulatory requirements and incorporates industry best practices applicable to this type of work.
c. Along with the voltage conversion program, this program is a high priority due to the primary driver being asset end of life. The safety and reliability risks associated with pole failure generally result in these investments taking priority over other projects or programs that are relatively more discretionary in terms of pacing and prioritization. Further, customer preferences identified during engagement activities indicated a higher degree of support for proactive end of life asset replacement compared to other categories of investments.
d. Where distribution line assets are replaced resulting from condition-based end of life assessments, there are generally no reasonable alternatives to replacement.

CNPI does however consider strategic opportunities to align end of life replacements with voltage conversion activities as described in the previous program.

2. Safety

The design and construction of line rebuilds are completed in accordance with USF Standards to meet the requirements of Ontario Regulation 22/04 and to ensure that no undue safety hazards exist.

3. Cyber Security, Privacy

N/A.

4. Co-ordination, Interoperability

CNPI meets regularly with its municipalities, road authorities and other agencies to coordinate future investment plans and identify opportunities for synergies. CNPI is also actively monitoring regulatory developments related to the Building Broadband Faster Act, 2021, in order to determine regulatory policy changes might support improved coordination between its distribution system planning efforts and the broadband deployment planning of telecommunication companies.

5. Environmental Benefits

Proactive replacement of end of life distribution line assets reduces the occurrence of spill from oil-filled pole mounted equipment during pole failures.

6. Conservation and Demand Management to Defer Infrastructure Projects

Considering that line rebuild investments are driven by condition-based asset end of life considerations rather than capacity requirements, CDM projects would not result in any deferral of these investments.

Category-Specific Requirements for Each Project/Program

As discussed above, a high priority is assigned to line rebuild programs due to the safety and reliability risks associated with end of life pole failure.

CNPI's ACA results, which are summarized in Section 3.2.3, indicate that wood poles and distribution transformer asset classes all have more than 50% of assets in very poor to fair condition. Ongoing line rebuild programs will result in replacement of a substantial number of poles and transformers. CNPI therefore expects these efforts to result in improved asset health indices for these asset classes by the end of the forecast period.

4.4.2.2.3 SR – OAKES DS (FORT ERIE)

General Information on the Project/Program

This project involves constructing a 34.5 kV to 4.8/8.3 kV wye substation to supply the southeast portion of CNPI's Fort Erie service area as 4.8 kV delta to 8.3 kV wye voltage conversion programs are completed in Fort Erie and the existing Station 12 is retired.

Section 5.1 of CNPI's APS, included as Appendix E, provides additional description of how this project fits into CNPI's overall plans for its Fort Erie system configuration following completion of voltage conversion activity. The total planned investment for this station is approximately $2 million.

Evaluation Criteria and Information Requirements for Each Project/Program

1. Efficiency, Customer Value, Reliability

a. The primary drivers for this investment are reliability and system performance. CNPI's APS evaluated reliability and system performance implications of Fort Erie system configuration options with and without this substation once voltage conversion efforts are complete, and recommended construction this substation.
b. The recommendation for this substation results from system planning studies and analysis that considers industry standards for system performance and best practices for contingency planning.
c. While this project is important from a reliability and system performance perspective, it ranks slightly lower than asset end of life replacements. The Fort Erie distribution could operate for a period of time without this station in service, although system losses would be higher and contingency options would be significantly limited, especially with any load growth.
d. Section 5.1 of CNPI's APS, included as Appendix E, provides detailed alternative analysis for various voltage conversion and system configuration options for the Fort Erie service area, with and without this substation.

2. Safety

The design and construction of this substation will be completed in accordance with the requirements of Ontario Regulation 22/04 to ensure that no undue safety hazards exist.

3. Cyber Security, Privacy

Any wired or wireless communication between SCADA endpoints, and other operational technology utilize private network communication exclusively, and activity on these networks is monitored by the company's Managed Security Services Provider ("MSSP").

4. Co-ordination, Interoperability

N/A.

5. ***Environmental Benefits***
   Including this substation in CNPI's Fort Erie system configuration after voltage conversion is complete will reduce losses as compared to a configuration where Station 12 is retired without being replaced.
6. ***Conservation and Demand Management to Defer Infrastructure Projects***
   Customers in this area have already achieved significant energy savings from past CDM programs, which are reflected in the load forecast used as an input to the APS.

Category-Specific Requirements for Each Project/Program

A number of system configuration options were examined in Section 5.1 of CNPI's APS as alternatives to constructing the Oakes DS. Alternatives that did not include the Oakes DS resulted in voltage performance issues in various areas of CNPI's systems for loss of supply from other substations. Even with significant investments in feeder upgrades between the other stations, performance issues are not completely resolved under certain contingencies.

Further, CNPI's alternative analysis indicated that significant reductions in system losses during normal operating configurations would be achieved by constructing Oakes DS. While this investment is important from a reliability and system performance perspective, CNPI does have some discretion with respect to the exact timing of the project if overall priorities within the voltage conversion program need to be adjusted in consideration other inputs to CNPI's system planning process, such as pole testing results and other inspections, or reliability trending.

4.4.2.2.4 SR – GANANOQUE DISTRIBUTED SUPPLY

General Information on the Project/Program

This project involves constructing a number of distributed 27.6 to 4.16 kV step-down transformer banks to allow the retirement of Gananoque DS in 2022. These investments are aligned with voltage conversion activity in the same area to ensure that the final configuration provides adequate supply capacity and performance during foreseeable contingency scenarios.

Total planned investment of approximately $1.3 million bridges the historical and forecasts periods covered by this DSP. The Gananoque Area Addendum to CNPI's APS, provides additional description of how this project fits into CNPI's overall plans for its Gananoque system configuration following completion of voltage conversion activity.

Evaluation Criteria and Information Requirements for Each Project/Program

1. Efficiency, Customer Value, Reliability

a. The primary drivers for this project are asset end of life, reliability and system performance. The proposed solution addresses critical asset retirement requirements in CNPI's Gananoque DS following unsuccessful efforts to obtain suitable land for a replacement substation.
b. The recommended for this substation results from system planning studies and analysis that considers industry standards for system performance and best practices for contingency planning.
c. This project is a high priority, with the majority of the investment already in progress from the historical period.
d. The Gananoque Area Addendum to CNPI's APS discusses alternatives that were considered to this project and the overall benefits resulting from the final configuration in the absence of other viable alternatives.

2. Safety

The design and construction of this substation will be completed in accordance with the requirements of Ontario Regulation 22/04 to ensure that no undue safety hazards exist. The retirement of Gananoque DS will resolve safety issues associated with deteriorating condition of existing substation structures and other assets.

3. Cyber Security, Privacy

Any wired or wireless communication between SCADA endpoints, and other operational technology utilize private network communication exclusively, and activity on these networks is monitored by the company's Managed Security Services Provider ("MSSP").

4. Co-ordination, Interoperability

CNPI consulted with the Town of Gananoque in order to identify suitable locations for a single larger substation to replace Gananoque DS, but was ultimately unsuccessful in identifying suitable land parcels. The alternative solution will avoid the need to expropriate land that would otherwise have higher value to the community for uses other than electrical substations.

5. ***Environmental Benefits***
   Completion of this project will allow retirement of the Gananoque DS, removing end of life oil-filled condition that is located close to a waterway.

6. ***Conservation and Demand Management to Defer Infrastructure Projects***
   This distributed step-down transformer project is aligned with voltage conversion efforts to partially offload the 4.16 kV to a point where the planned installations will have appropriate capacity and performance characteristics under normal and contingency scenarios.

Category-Specific Requirements for Each Project/Program

Section 2.4 of CNPI's AMP describes the overall configuration of CNPI's distribution system and substations in the Gananoque service area, identifying Gananoque DS assets as being in very poor to fair condition. CNPI's APS discusses the need to retire this substation by the end of 2022, and alternatives considered to replace the capacity that it supplies to the 4.16 kV distribution system. CNPI expects that longer-term voltage conversion efforts will further reduce 4.16 kV system loading, but will consider CDM or other alternatives to mitigate risk if increases to 4.16 kV system load occur at a faster pace than reductions resulting from voltage conversion programs.

4.4.2.2.5 SR – DISTRIBUTION TRANSFORMERS

General Information on the Project/Program

This program includes costs related to the purchase of distribution transformers required for end of life replacements, including proactive replacements during line rebuild activities, replacements during voltage conversion programs, and replacements due to failure. Total investments over the 2022-2026 period are planned at an average of approximately $575k per year, for a total of $2.9 million, which is roughly in line with investments of $2.8 million in the historical period.

Evaluation Criteria and Information Requirements for Each Project/Program

1. Efficiency, Customer Value, Reliability

a. The main driver of this program is asset end of life.
b. CNPI purchases transformers in accordance with industry standard specifications.
c. Replacement of failed transformers is a non-discretionary investment. Transformer replacements to support other planned programs and projects are high priority due to the efficiencies associated with replacing near end of life assets while already mobilized for line rebuilds.
d. Distribution transformers are generally not cost-effective to test maintain or repair as an alternative to end of life replacement.

2. Safety

From a safety perspective, all new transformers meet CNPI’s equipment approval requirements under Ontario Regulation 22/04. Proactive transformer replacements during planned line rebuild activities reduce any safety risks associated with sudden failure.

3. Cyber Security, Privacy

N/A.

4. Co-ordination, Interoperability

N/A.

5. Environmental Benefits

Proactive transformer replacements during planned line rebuild activities reduce the environmental risk associate with oil leaks from aging transformers.

6. Conservation and Demand Management to Defer Infrastructure Projects

N/A.

Category-Specific Requirements for Each Project/Program

System Renewal investments in transformers depend heavily on the volume of replacements during line rebuild programs, and to a lesser extent on the number of sudden failures. CNPI’s ACA results, which are summarized in Section 3.2.3, indicate that distribution transformer asset classes have more than 50% of assets in very poor to fair condition.

4.4.2.3 SYSTEM SERVICE

The following table summarizes CNPI's planned System Service investments over the forecast period.

Table 36: System Service Investment Summary for the Forecast Period (2022-2026)

SS Project/Program	2022	2023	2024	2025	2026	Total	Materiality
Lines							
Voltage Conversion (SS)	752	500	600	700	750	**3,302**	**> Threshold**
Line Rebuilds/Upgrades/Replacements (SS)	118	250	250	100	100	**818**	< Threshold
Stations							
Stevensville DS	1,417	-	-	-	-	**1,417**	**Unique Characteristics**
Station 19 Projects (SS)	148	-	-	-	-	**148**	< Threshold
67RT3 - New Backup RB on F1911	-	200	-	-	-	**200**	< Threshold
Killaly DS	-	-	-	-	500	**500**	**Unique Characteristics**
Other							
Distribution Automation and Reliability	714	650	400	400	400	**2,564**	**> Threshold**
Other	157	95	95	95	95	**537**	< Threshold
Total	**3,305**	**1,695**	**1,345**	**1,295**	**1,845**	**9,485**	

4.4.2.3.1 SS – VOLTAGE CONVERSION

General Information on the Project/Program

As described in Section 4.4.2.2.1, CNPI's voltage conversion program is aligned with end of life asset replacements to the extent practical, such that the majority of voltage conversion investments for the forecast period are captured under the System Renewal category.

In addition to the $13.6 million in System Renewal investments in voltage conversion, CNPI plans to invest $3.3 million under System Service over the forecast period. These investments relate to line segments where complete rebuilds are not required as voltage conversion programs move through a given area. Apart from the distinction that these investments do not relate directly to end of life line rebuilds, the information provided in Section 4.4.2.2.1 is equally relevant to the System Service portion of CNPI's voltage conversion program.

4.4.2.3.2 SS – STEVENSVILLE DS

General Information on the Project/Program

This project involves constructing a 34.5 kV to 4.8/8.3 kV wye substation to supply the Stevensville portion of CNPI's Fort Erie service area, in conjunction with voltage conversion from 2.4/4.16 kV wye to 8.3 kV wye voltage conversion programs are completed in Fort Erie and the existing Station 12 is retired.

Section 5.2 of CNPI's APS, included as Appendix E, provides additional description of how this project meets the long-term needs of this area of CNPI's distribution system. The total planned investment for this station is approximately $1.6 million in 2021 and 2022.

Evaluation Criteria and Information Requirements for Each Project/Program

1. Efficiency, Customer Value, Reliability

a. The primary drivers for this investment are reliability and system performance. CNPI's APS identified capacity, reliability and power quality concerns with maintaining the status-quo configuration for this area, and recommended construction this substation as the preferred solution.
b. The recommendation for this substation results from system planning studies and analysis that considers industry standards for system performance and best practices for contingency planning.
c. This project is a high priority within the System Service category due to the capacity and power quality concerns, in addition to reliability risk.
d. Section 5.2 of CNPI's APS, included as Appendix E, provides detailed alternative analysis for various combinations of substation, ratio bank and voltage conversion projects to address resolve identified issues and meet long-term needs in the Stevensville area.

2. Safety

The design and construction of this substation will be completed in accordance with the requirements of Ontario Regulation 22/04 to ensure that no undue safety hazards exist.

3. Cyber Security, Privacy

Any wired or wireless communication between SCADA endpoints, and other operational technology utilize private network communication exclusively, and activity on these networks is monitored by the company's Managed Security Services Provider ("MSSP").

4. Co-ordination, Interoperability

N/A.

5. Environmental Benefits

Construction of this substation will result in lower losses as compared to other alternatives assessed in CNPI's APS. Oil filled equipment in substations generally mitigates risk of oil releases to the external environment compared to ratio bank installations, due to the presence of oil containment and monitoring equipment.

6. Conservation and Demand Management to Defer Infrastructure Projects

The performance and reliability issues identified in this area cannot be mitigated by CDM activity due to the primarily residential nature of the load and the likelihood of future load growth in this area.

Category-Specific Requirements for Each Project/Program

A number of system configuration options were examined in Section 5.2 of CNPI's APS as alternatives to constructing the Stevensville DS, or alternatives to the configuration of this substation. Alternatives that did involve long-term use of ratio banks would limit future supply capacity to the area, require extensive reconductoring to resolve power quality issues, and would result in higher long-term system losses than the substation options. Similarly, alternatives involving the continued use of 4.16 kV (substation or ratio bank) result in higher system losses and extensive reconductoring requirements relative to the comparable 8.3 kV alternatives. As such, the APS recommended the construction of a 34.5 kV to 8.3 kV substation to supply this area.

4.4.2.3.3 SS – KILLALY DS

General Information on the Project/Program

As discussed in 4.3.1.3, CNPI's prior DSP identified a project to improve supply redundancy and replace protective devices switchgear in the Killaly DS. As described in Section 5.4.2 of the APS, recent failures have led to repairs that have replaced supply cables and primary protective devices, partially completing the scope of the previously planned project.

CNPI has included a $500k placeholder project for Killaly DS for 2026, which is subject to further scope definition and reprioritization in accordance with CNPI's system planning and capital budgeting processes described in this DSP, as further summarized below.

Evaluation Criteria and Information Requirements for Each Project/Program

1. Efficiency, Customer Value, Reliability

a. The primary drivers for this investment are asset end of life associated with asset condition in the existing substation and reliability since this substation is the primary supply for the majority of the East of Welland Canal portion of Port Colborne.
b. CNPI has identified risks associated with this substation through comprehensive asset condition assessment processes and through system planning studies and analysis that considers industry standards for system performance and best practices for contingency planning.
c. While this project is included in the forecast period due to asset end of life concern, those concerns are mitigated by the presence of redundant equipment for certain assets within the existing substation, allowing the project to be schedule at the end of the forecast period to better consider synergies with line rebuild requirements and associated voltage conversion opportunities.
d. CNPI is scheduled to complete pole testing activity in this area of Port Colborne in 2021. The results of this pole testing will provide insight into the relative priority of line rebuild projects and associated voltage conversion opportunities that could partially offload Killaly DS. Alternatives analysis similar to those shown for other substations in CNPI's APS will be completed for this substation as more information becomes available.

2. Safety

Safety considerations will be included in any analysis of alternatives, which will be developed during the forecast period.

3. Cyber Security, Privacy

Any wired or wireless communication between SCADA endpoints, and other operational technology utilize private network communication exclusively, and activity on these networks is monitored by the company's Managed Security Services Provider ("MSSP").

4. Co-ordination, Interoperability

To the extent that any identified alternative solutions require land acquisition, or could have synergies with other infrastructure projects, CNPI will engage the appropriate municipal and regional agencies and other third parties.

5. Environmental Benefits

Environmental considerations will be included in any analysis of alternatives, which will be developed during the forecast period.

6. Conservation and Demand Management to Defer Infrastructure Projects

Conservation programs or other demand reduction options will be considered to the extent practical in any analysis of alternatives, which will be developed during the forecast period.

Category-Specific Requirements for Each Project/Program

As summarized above, the specific scope of this project will be determined during the forecast period. In the event that pole testing results support significant line rebuilds in the general area, including voltage conversion in these rebuild programs could offload a substantial amount of load from the existing station, significantly impacting the alternatives analysis.

4.4.2.3.4 SS – DISTRIBUTION AUTOMATION AND RELIABILITY

General Information on the Project/Program

CNPI's system planning process described in Section 4.2.2 includes analysis of historical outage data. This analysis is incorporated into periodic reliability studies (see Appendix F) as well as regular monitoring and reporting of reliability performance (see Section 2.3.1.3 of this DSP). These efforts identify projects that could improve reliability and/or contingency performance, but do not fit into other investment categories.

The goal of maintaining an annual program for Distribution Automation and Reliability is to allow for identified reliability improvement projects to be implemented over time on a priority basis considering reliability trends and project costs. Many of these projects also have positive impacts on power quality, system maintainability, accommodation of REG projects, future cost savings, and/or progression toward Smart Grid implementation. This program also ensures that CNPI is meeting customer expectations regarding continued reliability improvements.

Investments in this category generally include installation or replacement of protection, control and monitoring devices on CNPI's distribution lines (e.g. SCADA-capable reclosers, fault indicators). CNPI has also recently installed additional wildlife guards to mitigate the risk of animal caused outages. Total investments over the forecast period are planned at $1.85 million.

Evaluation Criteria and Information Requirements for Each Project/Program

1. Efficiency, Customer Value, Reliability

a. The primary driver for this program is reliability. Secondary drivers are operational efficiencies, improved system performance, maintainability and operability. The selection, prioritization, and justification of individual projects in any given year will be based on the analysis of historical outage data as well as an analysis of system capacity and contingency plans.
b. CNPI reviews outage statistics in conjunction with system planning activities to identify areas for improvement. Outage analysis helps to identify any trending and worst performing feeders, while load flow studies identify capacity and voltage constraints during contingencies.
c. Investments in this program are relatively discretionary as compared to most other projects and programs, and as a result are given less priority. While justifications could be made for a large number of projects driven by reliability improvement, CNPI is mindful of the associated rate impacts and resource requirements. Planned spending on this program is therefore relatively low in comparison to other programs and projects included in the 2022-2026 plan, representing 4% of the total 5-year capital investments.
d. The projects selected for the current 5-year plan will be those that result in the most significant contingency improvements, reliability benefits and cost-saving

opportunities resulting from ongoing reliability and performance analysis during CNPI's system planning process.

2. ***Safety***
Automated restoration, increased remote switching and improved fault locating are expected to reduce the safety risks that are associated with outage restoration efforts in unfavourable conditions due to weather, time of day, or other factors.

3. ***Cyber Security, Privacy***
Any wired or wireless communication between SCADA endpoints, and other operational technology utilize private network communication exclusively, and activity on these networks is monitored by the company's Managed Security Services Provider ("MSSP").

4. ***Co-ordination, Interoperability***
The reliability-driven investments associated with this program are expected to incorporate modern SCADA-capable equipment that will serve as a foundation for future Smart Grid projects.

5. ***Environmental Benefits***
Projects under this program will result in replacement of some oil-filled equipment with oil-free equipment, minimizing the potential environmental impacts of equipment failure. In addition, reliability improvements resulting in a reduction of outage frequency would reduce the emissions associated with vehicles responding to after-hours outage events.

6. ***Conservation and Demand Management to Defer Infrastructure Projects***
N/A.

Category-Specific Requirements for Each Project/Program

As discussed above, this program is relatively discretionary in comparison to other projects and programs within the current 5-year plan. As a result, the consideration of a do-nothing approach for any specific project within this program would essentially maintain the status quo in terms of reliability, costs and contingency performance.

4.4.2.4 GENERAL PLANT

The following table summarizes CNPI's planned General Plant investments over the forecast period.

Table 37: General Plant Investment Summary for the Forecast Period (2022-2026)

GP Project/Program	2022	2023	2024	2025	2026	Total	Materiality
IT Software	901	1,250	800	800	700	**4,451**	**> Threshold**
IT Hardware	199	200	200	150	120	**869**	< Threshold
Fleet	545	120	505	462	462	**2,094**	**> Threshold**
Facilities, Yards, Land	231	115	185	135	135	**801**	< Threshold
Other	131	161	161	161	161	**775**	< Threshold
Total	**2,007**	**1,846**	**1,851**	**1,708**	**1,578**	**8,990**	

4.4.2.4.1 GP – IT SOFTWARE

General Information on the Project/Program

This program includes investments in software over the 2022-2026 period. Software systems include email applications, file/print services, CNPI's SAP ERP/CIS system, operating system, server/networking software, and office productivity software. There are other specific software applications that are used within CNPI that are unique to departmental needs.

Total planned investment in software over the forecast period is approximately $4.5 million.

Evaluation Criteria and Information Requirements for Each Project/Program

1. Efficiency, Customer Value, Reliability

a. The main drivers are asset end of life (software is replaced in conjunction with the vendor's maintenance schedule and lifecycle schedule), operational efficiency (increased integration between existing business systems), and customer service improvement (development of additional customer-facing tools or functionality).

b. This program ensures that CNPI is leveraging new software technologies to increase operational efficiencies.

c. A large portion of CNPI's software investments related to upgrades and replacement is non-discretionary to ensure that software is sufficiently current to apply security patches to address known vulnerabilities consistent with CNPI's cyber security strategy. CIS and ERP system development activity is often related to addressing policy changes mandated by the OEB, government or other authorities and is also often non-discretionary. Investments in other systems and integrations will result in operational efficiencies and process improvements, but are more flexible in terms of exact timing. These investments are also partially driven by customer feedback indicating a desire for improved reliability and improved communication during outages.

d. For IT investments generally, CNPI considers alternatives for upgrading vs. replacement of existing software/systems, as well as alternatives for in-house vs. hosted/managed/cloud-based solutions.

2. Safety

Software systems include investments that support the continual improvement of CNPI's integrated Health, Safety and Environmental management system.

3. Cyber Security, Privacy

Privacy and security practices will meet all regulatory requirements and will be consistent with the OEB Cybersecurity Framework as part of CNPI's overall cybersecurity strategy, which is described in CNPI's business plan, included with Exhibit 1.

4. Co-ordination, Interoperability

The development and integration of CNPI's IT systems is coordinated with other FortisOntario subsidiaries in order to reduce both the initial implementation and long-term management costs.

5. Environmental Benefits

N/A.

6. Conservation and Demand Management to Defer Infrastructure Projects

N/A.

Category-Specific Requirements for Each Project/Program

CNPI will continue to undertake non-discretionary investments in software development, upgrades and replacements as required to meet OEB-mandated processes and reporting requirements, to meet its overall business needs and to comply with its cyber security strategy. Discretionary software investments to meet customer-driven priorities and/or operational efficiencies will be evaluated in consideration of costs, benefits, and customer priorities as identified through customer engagement activities.

4.4.2.4.2 GP – FLEET

General Information on the Project/Program

This program includes all investments related to fleet, including:

- aerial devices (bucket trucks, radial boom derricks)
- cargo vans, pickup trucks and passenger vehicles
- trailers (open & enclosed) – for transporting poles, heavy materials, etc.
- other equipment such as forklifts, tensioning equipment, wood chipper, etc.

CNPI's total 2022-2026 planned investments for replacement of fleet assets is approximately $2.1 million.

Evaluation Criteria and Information Requirements for Each Project/Program

1. Efficiency, Customer Value, Reliability

a. The primary driver for this program is the replacement of end of life fleet assets at a rate that is sustainable with relatively consistent annual spending. An adequate fleet complement is required to support CNPI's capital and O&M programs, as well as for outage response. The overall type, age and condition of fleet assets is the primary source of information used to justify this program.

b. CNPI has developed and maintains a Fleet plan that is based on a sustained approach to tracking current Fleet conditions and managing replacement and maintenance schedules as further discussed under asset lifecycle management practices in Section 3.3.2.

c. The overall requirement to maintain an adequate fleet compliment to meet CNPI's day-to-day business requirements is considered a non-discretionary item and is among the highest priority programs within the General Plant category. Replacements are based on the expected economically useful life of each type of equipment and are staggered to maintain a relatively constant age profile for in-service fleet assets.

d. Sustained replacement of fleet assets on predictable cycles with relatively consistent year over year spending will result in the most efficient use of internal resources and the lowest program costs in the long term. Deferring replacements beyond replacement criteria will generally result in increased O&M costs and decreased productivity due to more frequent breakdowns.

2. Safety

CNPI's overall lifecycle management of fleet assets results in the availability of safe, reliable vehicles to support operational activities.

3. Cyber Security, Privacy

N/A.

4. Co-ordination, Interoperability

N/A.

5. Environmental Benefits

Newer fleet assets are generally more fuel efficient than the units being replaced. As a result, CNPI's fleet is expected to become more fuel efficient over time. CNPI is also increasingly considering EV's on a case-by-case basis, especially for smaller vehicles.

6. Conservation and Demand Management to Defer Infrastructure Projects

N/A.

Category-Specific Requirements for Each Project/Program

Annual fleet replacements typically include one aerial device, as well as a number of smaller approximately 3-6 smaller vehicles and miscellaneous equipment as required. Replacement decisions are based on evaluation of age, total km, condition assessment and evaluation of maintenance costs. This approach results in a sustainable fleet program that provides operational staff with a reliable compliment of vehicles, with a consistent age profile over time. The resulting annual capital and maintenance costs are predictable and the impact on other projects or programs due to urgent unexpected replacement or repairs is minimized.

ASSET MANAGEMENT PROGRAM (AMP)

Last Update: May 2021

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1 INTRODUCTION

1.1 NON-DISCLOSURE OF CONFIDENTIAL INFORMATION

This document describes the Canadian Niagara Power Inc. (CNPI) Asset Management Program (AMP) that informs and supports CNPI's Distribution System Plan (DSP). As such, this document and subsequent revisions to this document will be filed periodically with the Ontario Energy Board (OEB), at which point the information contained herein will form part of the public record. Accordingly, the contents of this document shall not:

a) disclose any customer-specific information;
b) provide data at a level of granularity that would allow the reader to infer or estimate any customer-specific information; or
c) disclose any personal, sensitive or confidential information that is protected from disclosure by CNPI's privacy policy or relevant privacy legislation.

1.2 OBJECTIVE

The fundamental objective of the AMP is to prudently and efficiently manage the planning and engineering, design, addition, inspection and maintenance, replacement, and retirement of all distribution assets in a sustainable manner that maximizes safety and customer reliability, while optimizing asset lifecycle costs.

This objective is met through the application of thorough and sound planning, prudent, justified budgeting, and ongoing oversight, documentation, and review of all efforts and expenditures while implementing the documented capital, and operating plans.

Using the AMP and other documents as inputs, CNPI's DSP outlines the various processes, activities, and forecasted expenditures that are required to ensure that CNPI continues to provide the safe, reliable, and efficient distribution of electricity to its customers.

There are three key principles that are integral to CNPI's distribution system planning process:

1) Meet the needs and expectations of its customers, as identified through regular customer engagement;
2) Provide safe, reliable, and high-quality of service to all of the customers of CNPI; and
3) Satisfy the first two principles in a sustainable manner, with a focus on long-term value and performance outcomes.

These key principles are derived from safety considerations; acts, regulations, codes and guidelines; good utility practice; and customer expectations.

1.3 SCOPE

This document describes the distribution system assets owned by CNPI, the processes and programs in place for managing those assets, and a summary of current asset condition.

This document is intended to provide a synopsis of the AMP at CNPI. For reasons of brevity and confidentiality, this document does not attempt to encompass all of the detailed information and activities that fully define the AMP. The purpose of this document is to provide an objective summary with sufficient detail to supply an overall understanding of CNPI's asset management efforts.

Prior versions of CNPI's AMP included detailed descriptions of CNPI's asset management processes in the context of overall system planning, and development of capital and O&M plans and budgets. As CNPI's DSP has continued to evolve, these process details and flow charts have been moved to the DSP, since the AMP is one of many inputs into CNPI's overall system planning process. Section 6 of this document summarizes how the AMP interacts with CNPI's other system planning processes over various planning horizons.

Prior versions of CNPI's AMP also included extensive appendices containing completed inspection forms and detailed test results. As CNPI has augmented its AMP to include a comprehensive third-party Asset Condition Assessment (ACA), the number of AMP appendices has been significantly reduced. Section 5 of this document contains a summary of the condition of CNPI's distribution assets. The complete ACA report, which is included as Appendix D to CNPI's 2022-2026 DSP, summarizes the various test results, inspection forms and other sources of asset condition information that support the assessment of asset condition and associated health indices.

1.4 ACTS, REGULATIONS, CODES AND GUIDES

The following is a partial listing of the acts, regulation, codes and guidelines that direct CNPI's operations and asset management processes:

1) CNPI's principal regulator is the OEB. Under the statutory purposes and objectives set out in the Electricity Act, 1998 (the "Electricity Act") and the Ontario Energy Board Act, 1998 (the "OEB Act"), the OEB has established a Distribution System Code (DSC) that defines how and under what conditions, a utility is to provide service and interact with its customers. It is prescriptive in nature and deals with virtually every aspect of utility operations including such things as connections and expansions, standards of business practice and conduct, quality of supply (reliability), infrastructure inspections, metering and conditions of service. CNPI's Conditions of Service, developed in accordance with the DSC, have been filed with the OEB and posted on CNPI's web site.
2) The Electrical Safety Authority (ESA) derives its authority from the Electricity Act. The ESA is responsible for ensuring the safety of all electrical installations in the province of Ontario for systems operating at a voltage less than 50kV under Ontario Regulation 22/04. Under the

regulation, every electrical installation and associated equipment must be installed in accordance with a design or standard approved by a professional engineer. Annual compliance audits are conducted by an approved third party and CNPI is required to sign a regulatory declaration stipulating that it has complied with the provisions of the regulation that are not subject to audit.

3) The Occupational Health and Safety Act (OHSA) governs how work is performed and is enforced by the Ministry of Labour. Protecting the health and safety of employees and the public is a top priority for CNPI, and there is an active joint health and safety committee that oversees safety aspects of operational activities. There is also a Central Environmental and Safety Committee (CESC) to centrally coordinate safety and reporting activities. Extensive training programs ensure that staff is competent to perform their duties. Every effort is made to ensure that employees have the right tools and protective equipment to do their job safely.
4) The Ministry of Environment, Conservation and Parks (MECP) is broadly responsible for the protection of the environment. Significant environmental aspects associated with CNPI's operations include managing and reporting of spills, emissions and hazardous waste, as well as protection of species at risk and sensitive habitats. CNPI maintains comprehensive policies, procedures and reporting systems to ensure compliance with all relevant environmental legislation.
5) Measurement Canada (MC) regulates CNPI's revenue metering activities, including requirements for equipment approval, installation, verification, reporting and technical aspects related to metering disputes.
6) The Ministry of Transportation (MTO) is the governing body with respect to activities associated with CNPI's fleet. It also mandates the requirements for traffic control at worksites that are near or on roadways.
7) CNPI's engineering activities are governed by the Professional Engineers Ontario Act (PEO). The PEO regulates codes of practice and ethics applicable to engineering staff and engineering activities.
8) CNPI owns distribution system assets in a number of municipalities in the Niagara Region as well as Eastern Ontario. The needs, rules and by-laws of these municipalities must be respected.
9) There are a host of other entities that mandate rules, programs and work practices. These include, but are not limited to the Electrical Utility Safety Association (EUSA); the Independent Electric System Operator (IESO); the Canadian Coast Guard; the St. Lawrence Seaway Authority, CN and CP Rails; various Conservation Authorities; and the Canadian Standards Association (CSA).

1.5 INFORMATION THAT SUPPORTS THE AMP AND DSP

The following sections provide examples of reports and studies supporting the AMP and/or the DSP with a short description of each. CNPI's DSP will generally include specific reports and analysis related to supporting forecasted levels of capital investment and system maintenance for the period covered by the DSP.

1.5.1 SYSTEM PLANNING AND RELIABILITY STUDIES

CNPI periodically prepares and reviews area planning studies and system reliability studies. The studies complement the AMP by focusing on long-term system performance independent of asset condition, and assessing reliability trends and issues caused by factors beyond asset failure or malfunctions. The interaction between these studies and the AMP is described in further detail in Sections 6.1 and 6.2.

1.5.2 THE CNPI CONSTRUCTION VERIFICATION PROGRAM (CVP)

As required by Ontario Regulation 22/04, CNPI performs all material procurement, project design, construction, and follow-up inspections in accordance with ESA-approved CVP, utilizing only approved construction standards. This process is reviewed and updated on an ongoing basis and informs CNPI capital and maintenance plans.

1.5.3 DISTRIBUTION SYSTEM AND SUBSTATION ASSESSMENTS

A comprehensive review of system and substation equipment and performance indicators is used to optimize preventative maintenance programs and to drive future capital plans. Key indicators such reliability, failure history, failure impacts, test results, safety factors and age are considered in the prioritization of capital and maintenance activities.

1.5.4 PREDICTIVE MAINTENANCE REPORTS

Results from predictive maintenance techniques such as infrared scanning, oil testing, conductor testing, pole testing, and insulation testing are used to assess the condition of individual system components. The overall assessment forms the basis for the development of maintenance, refurbishment, intervention, and equipment retirement strategies.

1.5.5 TECHNICAL STUDIES

Various technical reports are prepared on an as-needed basis, the results of which are incorporated into the AMP as required. Examples would include a Connection Impact Assessment (CIA) prepared for a customer installing embedded generation for net metering or load displacement purposes, or engineering analysis relating to the connection of a large load customer.

1.5.6 DISTRIBUTION SYSTEM INFORMATION

CNPI uses an integrated GIS which incorporates its distribution asset and maintenance records in a spatial data environment. The GIS is integrated with the corporate Systems, Applications and Products

(SAP) system, which is used by CNPI to perform financial, project work flow, materials management, metering, billing, and customer information system (CIS) activities.

CNPI supplements the GIS with linkages to legacy data repositories such as relational databases, Computer Aided Design (CAD) drawings, Global Positioning System (GPS) records, and electronic spreadsheets. Additionally, CNPI manages a variety of paper-based maintenance and inspection records.

2 DISTRIBUTION SYSTEM OVERVIEW

2.1 GENERAL OVERVIEW OF THE CNPI SYSTEM

CNPI is an amalgamation of three former distinct LDCs:

- Canadian Niagara Power, serving the Town of Fort Erie
- Port Colborne Hydro, serving the City of Port Colborne
- Eastern Ontario Power, serving the Town of Gananoque and some surrounding area

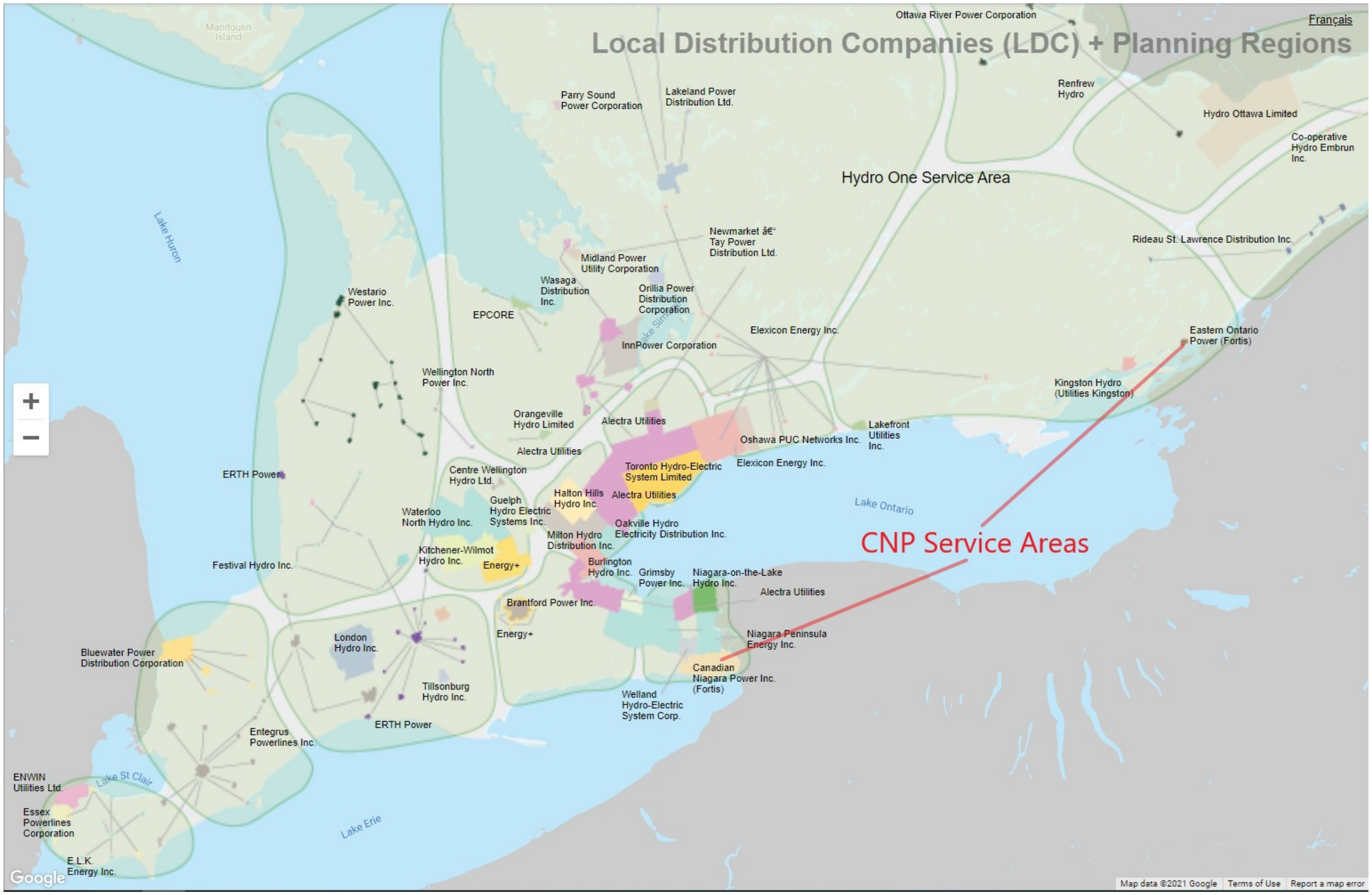
CNPI serves approximately 26,200 customers in Port Colborne and Fort Erie. CNPI serves an additional approximately 3,600 customers in the portion of its service area in and around Gananoque, operating as Eastern Ontario Power in the Gananoque area.

CNPI's combined service areas cover 357 square kilometres, approximately 80% of which is rural. CNPI's distribution system is comprised of approximately 1,555 km of primarily overhead distribution lines, and supplies a combined summer-peaking demand of approximately 100 MW.

Figures 1-3 show the extent of CNPI's Fort Erie and Port Colborne service areas (along the northeast shoreline of Lake Erie), and CNPI's Gananoque service area (operating as Eastern Ontario Power, northeast of Lake Ontario, along the St. Lawrence River).

Each of the three former LDCs that now comprise CNPI (CNPI, Port Colborne Hydro and Granite Power Corporation) were independently owned and operated for decades prior to operation and ownership changes involving CNPI in the 2001-2011 period. As a result, through a series of different planning decisions, operating philosophies, and construction standards, the three systems have distinct supply points and different primary system voltages, as detailed in Sections 2.2 to 2.4.

Figure 1: CNPI Service Areas (Southern Ontario Context)



Map Data © Google; LDC + Planning Region Overlay © IESO

Figure 2: Fort Erie (Red) and Port Colborne (Green) Service Areas

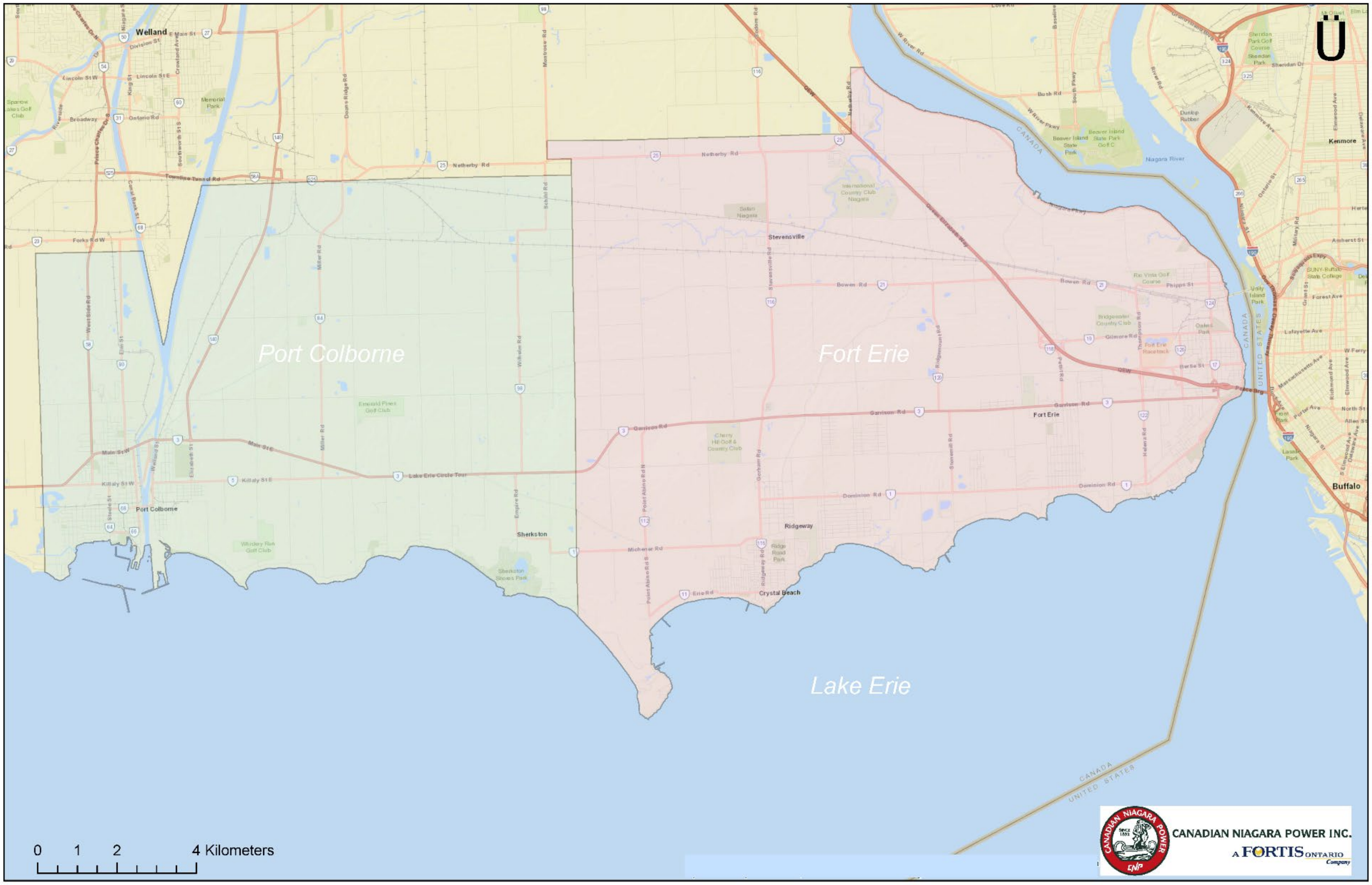
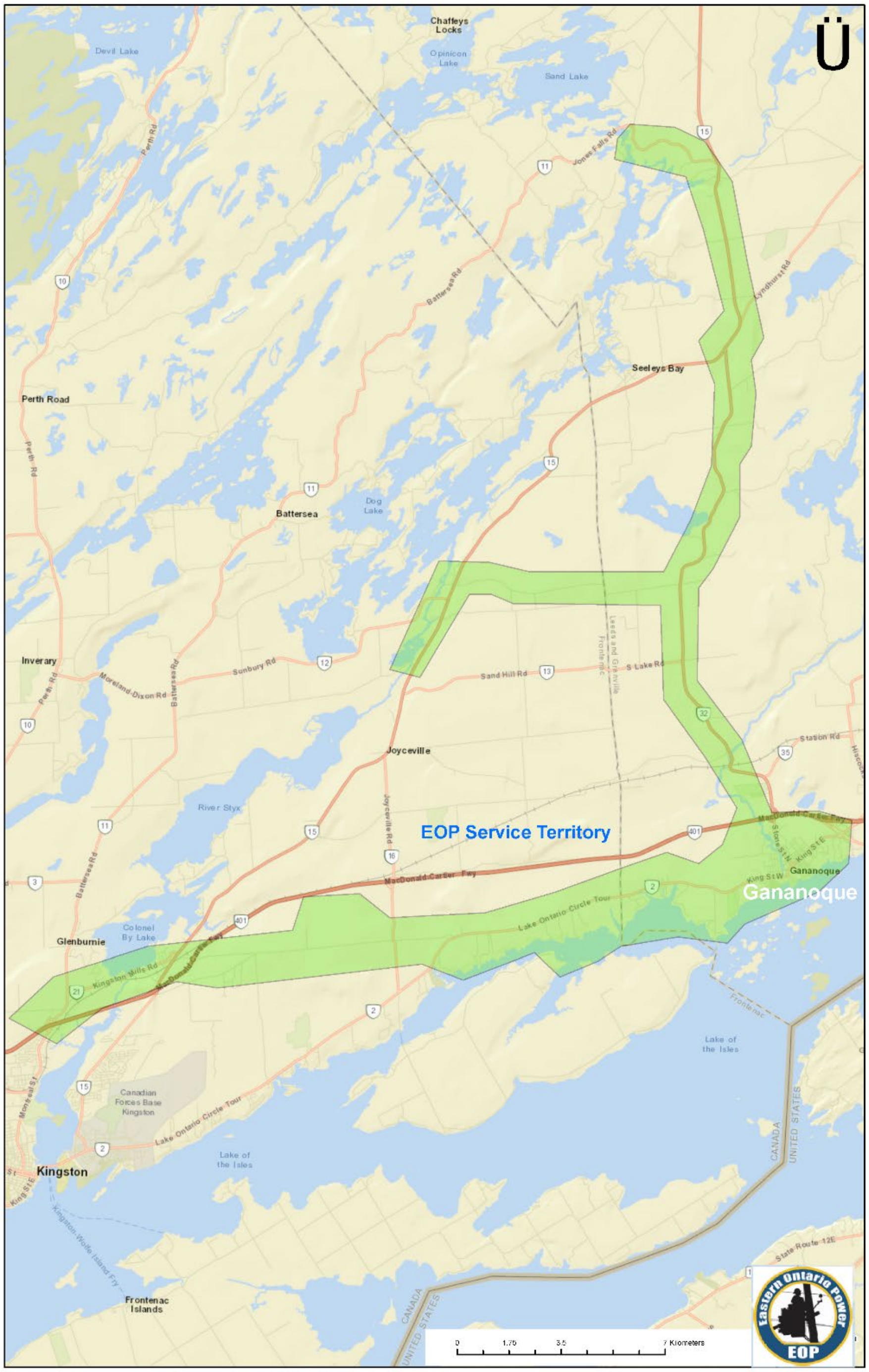


Figure 3: Gananoque Service Area (Green)



2.2 FORT ERIE DISTRIBUTION SYSTEM

2.2.1 SYSTEM CONFIGURATION AND VOLTAGE LEVELS

The CNPI distribution system in Fort Erie is supplied from the CNPI-owned 115kV transmission system that feeds Stations 17 and 18, the two transmission substations in Fort Erie. Both transmission substations supply 19.9/34.5 kV distribution feeders that provide all of the electricity for the Fort Erie distribution system.

The 34.5 kV feeders supply three step-down distribution substations (Stations 12, 19 and Gilmore DS), 28 step-down ratio banks (“Ratio Banks” or “Rabbits”), large commercial/industrial customers, large residential subdivisions, and rural customers.

The distribution substations and ratio banks transform to voltages of 4.8 kV delta, 4.8/8.3 kV, and 2.4/4.16 kV. The variety of distribution voltages used in the Fort Erie distribution system and the uncommon nature of some of the voltage classes present challenges to the planning and operation of the system.

Due to historical changes in planning and construction policies, and as a result of historical service area amalgamations, CNPI employs a wide variety of distribution voltages. Appendix A1 contains a map of the Fort Erie system showing lines by voltage class. The distribution systems associated with the various voltage classes are summarized in the remainder of this section.

2.2.1.1 19.9/34.5 kV (Wye)

The 34.5 kV distribution system is shown in orange on the system map in Appendix A1.

This voltage was introduced to serve as a higher-voltage distribution system to add capacity and efficiently supply distribution substations and larger load centers. The 34.5 kV feeders from each transmission station are radially operated, but are installed with several normally open feeder interties to facilitate load transfers under planned or emergency conditions. The distribution system is designed to allow the entire Fort Erie load to be served by either Transmission Station 17 (with four available feeders) or 18 (with seven available feeders). This configuration provides significant operating flexibility to allow for planned system maintenance to be carried out with minimal or no disruption to customers. In forced outage situations involving 34.5 kV feeders, the feeder interties facilitate isolation of faulted components and the rapid restoration of the majority of affected customers.

The 34.5 kV voltage level is rare in Ontario. Purchase costs for equipment in this voltage class are higher than the 27.6 kV systems that are more common in Ontario. This is particularly true on underground portions of the system. Switching and isolation issues are also more complex than with lower voltages.

Conversely, the 34.5 kV feeders provide a high degree of ‘reach’ and capacity. A typical nonemergency rating for these feeders is approximately 28 MVA. At moderate load levels, these feeders can run longer distances (>25km) while maintaining acceptable voltage levels and minimizing losses. Conductor sizes have been standardized at 336 kcmil aluminum for all new main 34.5 kV lines.

The use and expansion of this voltage level has generally focused on:

- Supply of the step-down substations and ratio banks
- Servicing large commercial/industrial customers

2.2.1.2 4.8 kV (Three-Wire Delta)

The 4.8 kV delta distribution system is shown in red on the system map in Appendix A1.

Historically, this was the earliest 60 Hz distribution voltage in Fort Erie and for many years was the sole distribution system. A delta configuration involves three single-phase transformers (or in the case of a three-phase transformer, the three windings) connected together without a neutral. As loads increased and feeders were extended, the 34.5 kV distribution system was introduced to serve distribution substations and larger loads, thereby relieving the overloaded 4.8 kV delta system, improving voltage regulation, and reducing system losses.

CNPI's aging 4.8 kV delta distribution system presents significant safety and operational concerns:

- The absence of a system neutral raises significant challenges for system protection/relaying and the effective balancing of loads across phases. The most significant risk with the delta system is the inability to detect single phase faults as there is no ground reference on this system. This presents a safety risk to both the public and workers in downed conductor scenarios.
- From an operational perspective, substations servicing the delta system consist of legacy relay-controlled breakers with negligible ground fault detection capability. The lack of ground fault detection limits CNPI's ability to determine fault locations contributing to lengthy response and restoration durations during unplanned events.
- As indicated elsewhere in this document, many of the substation and distribution line assets associated with the 4.8kV delta system are at or nearing end of life.
- Aging assets present an increased risk of failure, while overall reduction in the number of substations and feeders supplying this voltage limits options available for quick restoration following an outage.

Based on the risks associated with operating a delta distribution system, for several years one of the primary objectives of the CNPI capital program has been the conversion of the 4.8 kV delta system to an 4.8/8.3 kV system, and in some cases to 19.9Y/34.5 kV. A wye configuration involves three single-phase transformers (or, in the case of a three-phase transformer, the three windings) connected together along with a neutral. Station 12 is now the only distribution substation supplying 4.8 kV delta loads. Load previously supplied from other 4.8 kV Delta substations (Stations 13 and 15) was either converted to 8.3 kV wye or was transferred to 4.8 kV ratio banks in certain areas. Additional details on the drivers for specific projects related to CNPI's 4.8 kV delta to 8.3 kV wye voltage conversion program in Fort Erie are provided in CNPI's DSP.

2.2.1.3 4.8/8.3 kV (Four-Wire Wye)

The 8.3 kV distribution system is shown in green on the system map in Appendix A1.

This voltage was introduced as an economic option for converting the legacy 4.8 kV delta system to a wye-connected system. Although not a particularly high distribution voltage by modern standards, the 8.3 kV system provides the advantage of being able to re-use transformers and other line components of the existing 4.8 kV delta system, with the exception of lightning arresters and three-phase pad-mount transfers. This improves the feasibility of systematic voltage conversion from the delta system. In practice, voltage conversions from 4.8 kV delta system to 8.3 kV wye often necessitate extensive pole and framing replacements, as the legacy 4.8 kV delta lines are often supported by wooden poles where the size and/or condition are insufficient to meet current design standards for 8.3 kV construction.

In recent years, Station 19 in Ridgeway in the southwest portion of the Fort Erie service area, and Gilmore DS in the northeast portion of the Fort Erie service area, supplied feeders at this voltage level. Much of the recent voltage conversion activity focused converting load in the QEW-North area to be supplied from the new Gilmore DS, which was placed in service in 2016.

The distance between Station 19 and Gilmore DS is a concern from a contingency standpoint, especially as load served from these substations continued to increase as more load was converted from 4.8kV delta to 8.3kV wye. Feeders at this voltage level are also increasing in length to beyond optimal levels as more loads are converted.

In accordance with CNP's 2017-2021 DSP, a new 34.5 kV to 8.3 kV distribution substation (Rosehill DS) is being constructed in the south-central portion of the Fort Erie service area. Upon completion in 2021, Rosehill DS will facilitate voltage conversion for the majority of CNPI's outstanding 4.8 kV delta system which is in the QEW-South area. As described in detail in CNPI's DSP, Rosehill DS, in combination with other investments outlined in CNP's 2022-2026 DSP will also address system performance and contingency concerns associated with the current status of the 8.3 kV wye system configuration.

2.2.1.4 2.4/4.16 kV (Wye)

The 4.16 kV distribution system is shown in magenta on the system map in Appendix A1. This voltage class is found only in the Stevensville section of the Fort Erie service area, located in the northwest portion of Fort Erie. This area was inherited from the former Ontario Hydro when the franchise boundary was amended to match the municipal boundary. In the Stevensville area, ratio banks are used to supply the 4.16 kV distribution system covering a large rural geographical area with low, but increasing, customer density.

CNPI's 2022-2026 DSP discusses performance and contingency issues associated with the current configuration of the 4.16 kV system and future investments.

2.2.1.5 7.6 kV (1 phase, Wye)

There are three pockets of this voltage in Fort Erie:

- Crescent Road, near Woodside Court
- Dodd's Court
- Gorham Road, near Wellington and Brewster

Each of the above areas contains a relatively small single-phase underground residential system. The first area is supplied by a single ratio transformer, whereas the others have two installed ratio transformers that can each supply the entire load.

2.2.1.6 13.8 kV (Three-Wire Delta)

There is a single ratio transformer (5RT1) supplying 13.8 kV delta to a commercial customer located on Concession Ave., south of Gilmore Rd. in Fort Erie.

2.2.2 DISTRIBUTION SUBSTATIONS AND RATIO BANKS

CNPI's distribution substations in Fort Erie have been gradually rebuilt or replaced with greenfield stations in recent years in conjunction with the system voltage conversion efforts described above. The following sections provide an overview of existing distribution substations and ratio banks in CNPI's Fort Erie service area.

Table 1: Summary of Fort Erie Distribution Substations

Station	Secondary Voltage	# of Transformers	Transformer Age	Total Capacity (MVA)[1]	# of Feeders
Station 12	4.8 kV Delta	3	1963, 1977, 2001	23.5	12
Station 19	4.8/8.3 kV Wye	2	1999 (2)	26.6	6
Gilmore	4.8/8.3 kV Wye	2	2014, 2016	20	4
Rosehill[2]	4.8/8.3 kV Wye	2	2020 (2)	20	6

[1] These numbers represent the sum of the highest nameplate rating (i.e. the fan-cooled rating where applicable) of all transformers.
[2] Rosehill DS construction initiated in 2020, to be completed in 2021.

2.2.2.1 STATION 12

Station 12 is located in the eastern portion of CNPI's Fort Erie service area, and supplies most of the remaining 4.8 kV delta connected load south of the QEW.

As of 2020, Station 12 supplied a peak load of over 9 MW, or just under one-fifth the total load in Fort Erie. As remaining 4.8 kV delta load is converted to 8.3 kV wye and transferred to other substations, load on Station 12 is expected to gradually decrease to zero, at which point the station will be rebuilt to supply 8.3 kV wye.

Station 12 has redundancy in terms of 34.5 kV supply, 34.5-4.8 kV transformation, and 4.8 kV feeders. Either of the 34.5 kV supply feeders and any of the 34.5-4.8 kV transformers can carry the entire station load if required. As the sole remaining substation supplying 4.8 kV delta, this redundancy allows any single contingency to be addressed with appropriate load transfers between feeders on the 4.8 kV system. CNPI's 2022-2026 DSP provides additional detail on reliability considerations, historical investments, and future investments involving Station 12.

2.2.2.2 STATION 19

Station 19 supplies 8.3 kV wye feeders in the southwestern portion of CNPI's Fort Erie service area (e.g. Ridgeway, Crystal Beach, Thunder Bay, and surrounding areas). It was the first CNPI substation constructed to supply 8.3 kV wye load, and the load on this station has increased steadily as 4.8 kV delta to 8.3 kV wye voltage conversion programs have been completed.

Station 19 has redundancy in terms of 34.5 kV supply, 34.5-8.3 kV transformation, and 8.3 kV feeders. Either of the 34.5 kV supply feeders or 34.5-8.3 kV transformers can carry the entire station load if required. However, the geographic distance between Station 19 and Gilmore DS, and the presence of mostly 4.8 kV delta feeders in the QEW-South area between these two stations, means that there is no opportunity to transfer load to another station. CNPI's 2022-2026 DSP provides additional detail on reliability considerations and investments involving CNPI's 8.3 kV system and associated substations (Station 19, Gilmore DS and Rosehill DS).

2.2.2.3 GILMORE DS

Gilmore DS supplies 8.3 kV wye feeders in the northeastern portion of CNPI's Fort Erie service area, primarily supplying the area North-QEW area. This station was placed in service in 2016, replacing the prior 4.8 kV delta supply from Station 15 on the same site.

Gilmore DS is immediately adjacent to CNPI's 115-34.5 kV Station 18 TS. It has redundancy in terms of 34.5 kV supply, 34.5-8.3 kV transformation, and 8.3 kV feeders. Either of the 34.5 kV supply feeders or 34.5-8.3 kV transformers can carry the entire station load if required. However, the geographic distance between Gilmore DS and Station 19, and the presence of mostly 4.8 kV delta feeders in the QEW-South area between these two stations, means that there is no opportunity to transfer load to another station.

CNPI's 2022-2026 DSP provides additional detail on reliability considerations and investments involving CNPI's 8.3 kV system and associated substations (Station 19, Gilmore DS and Rosehill DS).

2.2.2.4 ROSEHILL DS

Construction of Rosehill DS was initiated in 2020 and will be placed in service in 2021. Once in service, this station will supply 8.3 kV feeders in the south-central portion of CNPI's Fort Erie service area, facilitating the 4.8 kV delta to 8.3 kV wye conversion in the QEW-South area, where the majority of remaining 4.8 kV delta load is concentrated.

Rosehill DS will have redundancy in terms of 34.5 kV supply, 34.5-8.3 kV transformation, and 8.3 kV feeders. Either of the 34.5 kV supply feeders or 34.5-8.3 kV transformers will be able to carry the entire station load if required.

In addition to facilitating voltage conversion in the QEW-South area, Rosehill DS provides an 8.3 kV wye source that is approximately centered between Station 19 and Gilmore DS. In combination with planned 2022-2026 voltage conversion work and other investments, Rosehill DS will significantly reduce contingency risks and will improve overall system performance. CNPI's 2022-2026 DSP provides additional detail on reliability considerations and investments involving CNPI's 8.3 kV system and associated substations (Station 19, Gilmore DS and Rosehill DS).

2.2.2.5 RATIO BANKS

CNPI has 34[3] ratio banks installed in its Fort Erie service area. Many of these units are in place on a temporary basis to facilitate voltage conversion from 4.8 kV delta to 8.3 kV wye. Some ratio banks are also in place to address contingency issues, to supply low-density areas, or to supply specific underground subdivisions or customers at unique voltage levels where existing equipment at those voltage levels is not yet at end-of-life.

Three ratio banks also supply a 2.4/4.16 kV wye distribution system in the Stevensville area. CNPI's 2022-2026 DSP discusses performance and contingency issues associated with the current configuration of the 4.16 kV system and planned investments in this area.

There are some disadvantages of using Ratio Banks compared to distribution substations, including the following:

- Ratio banks increase system complexity because they result in scattered load serving centers, compared to a distribution substation that would provide a concentrated load-serving point.
- Each Ratio Bank installation requires a certain footprint and is typically aesthetically displeasing. This limits the potential locations where they can be deployed.

[3] This number includes the 28 ratio banks discussed in Section 2.2.1 with a source connection to 19.9/34.5 kV wye feeders, plus 6 ratio banks with source connections to other voltages, as detailed in Table 2.

- Ratio Banks result in higher transformation losses compared to a distribution station.
- Platform-mounted ratio banks have had higher failure rates and result in lower reliability compared with ground-mounted and fenced solutions.
- Contingency options to address equipment failure are typically limited, often requiring complete replacement to fully restore power (i.e. the transformer and feeder redundancy associated with substations isn't included in the design of most ratio banks and downstream lines).

However, Ratio Banks have comparatively low initial costs and quick installation times compared to traditional substations. Accordingly, they provide an economic and flexible interim measure as longer-term voltage conversion is carried out. They are particularly cost-effective for this purpose in rural areas with low-density and widely scattered load centres.

Table 2 provides a summary of the ratio banks installed in the Fort Erie service area.

Table 2: Summary of Fort Erie Ratio Banks

Ratio Bank	Year	# of Phases	Source Voltage (kV)[4]	Load Voltage (kV)[4]	kVA
10RT1	2001	3	34.5 wye	4.8 delta	1500
10RT12	2016	1	34.5 wye	8.3 wye	250
10RT13	2019	1	34.5 wye	8.3 wye	500
10RT14	1992	3	34.5 wye	4.8 delta	1500
10RT2	1996	1	34.5 wye	8.3 wye	250
10RT3	2015	3	34.5 wye	4.8 delta	1500
10RT6	2015	1	34.5 wye	8.3 wye	300
10RT7	2019	1	34.5 wye	8.3 wye	500
10RT8	2019	1	34.5 wye	8.3 wye	500
10RT9	2016	1	34.5 wye	8.3 wye	100
11RT1	2003	3	34.5 wye	4.8 delta	1500
1268RT1	2003	1	4.8 delta	8.3 wye	500
1268RT2	2003	1	4.8 delta	8.3 wye	500
1563RT1	1978	1	4.8 delta	7.6 (1-phase)	167
2RT1	1996	3	34.5 wye	4.8 delta	1500
2RT2	2018	3	34.5 wye	4.8 delta	750
5RT1	2000	3	34.5 wye	13.8 delta	1500
5RT10	2017	1	34.5 wye	8.3 wye	300
5RT11	2019	1	34.5 wye	8.3 wye	500
5RT12	2019	1	34.5 wye	8.3 wye	500

[4] Voltages are listed in the table as the nominal phase-to-phase voltage and indicate wye vs. delta operation. For wye-connected systems, the actual phase-to-neutral connection voltage is equal to the listed voltage divided by 1.732 (e.g. 34.5 kV wye ratio banks are connected at 19.9 kV phase-to-neutral and 8.3 kV wye ratio banks are connected at 4.8 kV phase-to-neutral).

Ratio Bank	Year	# of Phases	Source Voltage (kV)[4]	Load Voltage (kV)[4]	kVA
5RT2	2018	3	34.5 wye	4.8 delta	750
5RT4	1993	2	34.5 wye	4.8 delta	500
5RT5	1993	2	34.5 wye	4.8 delta	500
5RT7	2004	2	34.5 wye	4.8 delta	500
5RT8	1996	3	34.5 wye	4.8 delta	1500
5RT9	2017	1	34.5 wye	8.3 wye	300
67RT3	2000	3	34.5 wye	4.8 delta	1500
67RT5	1992	1	4.8 delta	34.5 wye	167
8RT1	2x1988 1x2004	3	34.5 wye	4.16 wye	1500
8RT2	2004	3	34.5 wye	4.16 wye	1500
9RT1	2004	3	34.5 wye	4.16 wye	1500
9RT2	1996	3	34.5 wye	4.8 delta	1500
GF1RT1	2018	3	8.3 wye	4.8 delta	500
GF4RT1	2018	3	8.3 wye	4.8 delta	500

2.3 PORT COLBORNE DISTRIBUTION SYSTEM

2.3.1 SYSTEM CONFIGURATION AND VOLTAGE LEVELS

The Port Colborne distribution system is supplied mainly from Hydro One's Port Colborne Transformer Station (TS), located in the south end of the city. This substation transforms the power supply from Hydro One's 115 kV transmission voltage down to the distribution voltage of 27.6 kV.

Port Colborne TS supplies four 27.6 kV distribution feeders that serve the majority of the load in CNPI's Port Colborne service area. These feeders are owned by CNPI, with the ownership demarcation generally at the outer perimeter of Port Colborne TS. Hydro One has recently completed a significant rebuild of the Port Colborne TS and made other transmission system improvements to improve supply reliability to Port Colborne.

A small portion of the supply to Port Colborne is delivered to the northwest section of the city by one 27.6 kV feeder that originates from Hydro One's Crowland TS in Welland. CNPI owns the section of this feeder that is located in the Port Colborne service territory, while Hydro One owns other sections of the feeder.

The map in Appendix A1 shows the extent of CNPI's five 27.6 kV feeders in Port Colborne.

CNPI owns and operates five Distribution Substations (DS's) that transform the 27.6 kV down to 4.16 kV, generally used to supply the more densely populated areas of its Port Colborne service area.

CNPI also operates 27.6 kV-4.16 kV (three-phase) or 16 kV-2.4 kV (single-phase) ratio banks to supply the remainder of the 4.16 kV system. These are generally isolated pockets of the original 2.4/4.16 kV system still awaiting voltage conversion.

The Welland Canal runs generally north-south and forms a major geographical barrier within the City of Port Colborne. This makes it difficult and expensive (technically and politically) to have circuits passing from east to west over/under the canal. There are four 27.6 kV and one 4.16 kV feeder crossings at three locations along the canal in Port Colborne. Three of the distribution substations in Port Colborne are on the west side of the Welland Canal and two, Killally DS and Sherkston DS (Beach DS), are on the east side. There are several 4.16 kV interconnections among the DS's on the West side of the canal. However, there are no interconnections between the two substations of the East side of the canal, and only a single 4.16 kV interconnection of limited capacity between the east and west sides of the canal.

2.3.1.1 16/27.6 KV WYE

The 27.6 kV distribution system is shown in light red on the system map in Appendix A1. The five 27.6 kV feeders in Port Colborne act as the trunk distribution system supplying five stepdown Distribution Substations (DS's), fifteen step-down "Ratio Banks" or "Rabbits", several larger commercial/industrial customers, residential subdivisions, and many of the more rural area. The distribution substations and

Ratio Banks transform electricity down to a distribution voltage of 4.16 kV. The five 27.6 kV feeders are radially configured, but are interconnected at several locations via “Normally Open” points to facilitate load transfers under planned or emergency conditions. This provides significant operating flexibility on the 27.6 kV system to allow for planned system maintenance to be carried out with minimal or no disruption to customers. In forced outage situations, it facilitates isolation of faulted components along with the expedient restoration of the majority of affected customers.

Nearly all of the 27.6 kV system is overhead, and the main 3-phase lines are generally constructed of large gauge conductor, typically 336 kcmil aluminum.

2.3.1.2 2.4/4.16 KV WYE

The 4.16 kV distribution system is shown in magenta on the system map in Appendix A1. It supplies the more densely populated areas of Port Colborne, as well as more rural areas that have not been converted to 27.6 kV. It is an older system and is generally in poorer condition compared to the 27.6 kV system.

While there is at present generally sufficient transformation capacity at the distribution substations on the west side of the canal in order to meet normal and emergency needs, there are some instances of 4.16 kV lines having conductors that are too small to allow load transfers during contingency situations. This limits the ability to effect inter-feeder or interstation load transfers, and presents challenges to maintaining system reliability. Capital programs in recent years have continued to upgrade various sections of conductor on the 4.16 kV system to provide additional capacity and enhance transfer capability between feeders and distribution substations. Planned capital investments will continue to address capital and contingency concerns, as described in CNPI’s 2022-2026 DSP.

2.3.2 DISTRIBUTION SUBSTATIONS AND RATIO BANKS

All of CNPI’s distribution substations in Port Colborne supply 2.4/4.16 kV wye feeders from connections to 16.0/27.6 kV wye feeders. Distribution substation investments in Port Colborne have been focused on replacing end-of-life assets and adding redundancy where practical, in order to reduce the likelihood of equipment failure and to improve contingency performance following a failure. The following sections provide an overview of existing distribution substations and ratio banks in CNPI’s Port Colborne service area.

Table 3: Summary of Port Colborne Distribution Substations

Station	East or West of Welland Canal	# of Transformers	Transformer Age	Total Capacity (MVA)[5]	# of Feeders
Jefferson	West	1	2018	5	3
Catharine	West	1	1977	6.7	4
Fielden	West	2	2014, 2019	15.2	7
Killaly	East	2	1979[6]	9	4
Beach/ Sherkston	East	2	1959, 2009	10[7]	4

2.3.2.1 WEST OF WELLAND CANAL SUBSTATIONS (JEFFERSON, CATHARINE, FIELDEN)

The 4.16 kV distribution system in the portion of CNPI's Port Colborne service area located west of the Welland Canal is supplied by three distribution substations, as shown in Appendix A1:

- Jefferson DS supplies the southwest portion of the 4.16 kV system west of the canal
- Catharine DS supplies the southeastern portion of the 4.16 kV system west of the canal
- Fielden DS supplies the central portion of the 4.16 kV system west of the canal

The lower-density areas in the northern portion of CNPI's service area west of the canal are either supplied directly at 27.6 kV or supplied using ratio banks (see Section 2.3.2.3).

CNPI's 2022-2026 DSP provides additional detail on reliability and contingency considerations, along with discussion of investments involving these three substations.

JEFFERSON DS

Jefferson DS was rebuilt in 2018-2019 for end-of-life asset replacement reasons. This substation has redundancy on the 4.16 kV side, with ability to transfer loads between three feeders. There is a single 27.6 kV supply to the station, and a single 27.6-4.16 kV transformer, requiring the 4.16 kV load normally supplied by this station to be transferred to Fielden DS and Catharine DS in the event of major equipment or supply feeder outages. The overall size of this substation property limits the ability to add a second power transformer.

[5] These numbers represent the sum of the highest nameplate rating (i.e. the fan-cooled rating where applicable) of all transformers.
[6] These transformers were refurbished in 2003 and 2006.
[7] One of the two transformers (T2 – 2009 vintage) is rated 10 MVA and supplies all load. T1 (1959 vintage) rated 5MVA serves as an energized backup unit only.

CATHARINE DS

Catharine DS was originally constructed in 1977, with all equipment being of the original vintage. Both primary and secondary metal-clad switchgear incorporated fused protection, with no ability to incorporate SCADA notification/control, and no ability to capability to limit arc-flash exposure. This station is being rebuilt in 2021, and due to property size constraints will remain a single-element station (e.g. single 27.6 kV supply and single power transformer, similar to Jefferson DS). The new station will incorporate SCADA control on both primary and secondary protections. In the event of major equipment failure, or a sustained outage to the 27.6 kV supply feeder, the 4.16 kV load normally supplied by this substation must be transferred to other stations (e.g. Fielden DS and Jefferson DS).

FIELDEN DS

Fielden DS was constructed in 2004 and expanded in 2015, which allowed the end-of-life Barrick DS to be retired at that time. All equipment is relatively new and in good condition. In conjunction with the Jefferson DS rebuild in 2018, a second 27.6 kV feeder supply was added to Fielden DS, and an additional 4.16 kV feeder was brought out of Fielden DS to facilitate load transfers. As a result, the current configuration of Fielden DS now includes redundancy in terms of 27.6 kV supply, 27.6-4.16 kV transformation, and 4.16 kV feeders. A single contingency at Fielden DS can therefore be addressed by switching to isolate the faulted component. Fielden DS also provides critical support for contingencies involving Jefferson DS and/or Catharine DS, though additional investments are required to address performance issues during certain contingencies as further discussed in CNPI's 2022-2026 DSP.

2.3.2.2 EAST OF WELLAND CANAL SUBSTATIONS (KILLALY, BEACH)

The portion of CNPI's Port Colborne service area located east of the Welland Canal covers a large geographical area, as illustrated in Appendix A1. The distribution system supplying this area consists of three main areas:

- Higher density areas that are close to the east side of the Welland Canal are supplied at 4.16 kV, from the Killaly DS
- A higher density area in Sherskton (on the eastern edge of the Port Colborne boundary) and the surrounding area is supplied at 4.16 kV from the Beach DS (also referred to as Sherskton DS).
- Load in lower-density rural areas are either supplied directly from 27.6 kV feeders or from ratio banks supply pockets of 4.16 kV load from 27.6 kV feeders.

As a result of this configuration, Killaly DS and Beach DS each supply localized 4.16 kV systems, without any 4.16 kV interconnections between the stations available for load transfer.

Historical investments in the portion of CNPI's Port Colborne service area east of the Welland Canal have focused on reducing contingency risk associated with the two stations in this area.

KILLALY DS

The Killaly DS is supplied by a single 27.6 kV feeder, but has redundancy in terms of 27.6-4.16 kV transformation, and 4.16 kV feeders. In recent years, investments have been made to replace 27.6 kV fuses with electronic reclosers and install two new sets of 28 kV ingress cables from separate poles on the 27.6 kV system. These investments have reduced the risk of a full station outage. While transformers in this station are in relatively poor condition, the station load is low enough that the in the event of a transformer outage, the entire load can be supplied from the half of the station remaining in service. CNPI's 2022-2026 DSP discusses ongoing contingency risks and investments alternatives to address these risks.

BEACH DS

This substation was commissioned in 2009, when a new 7.5/10 MVA transformer was installed as the primary supply for 4.16 kV load in the surrounding area. An existing 5 MVA transformer (1959 vintage) was retained and kept on potential as an emergency backup, since this substation has no interconnections to other 4.16 kV supplies and the local load is too large to reasonably supply from ratio banks. CNPI's 2022-2026 DSP discusses how potential load increases and contingency considerations might impact future investment alternatives in this area.

2.3.2.3 RATIO BANKS

CNPI has 15 ratio banks installed in its Port Colborne service area. These are installed mainly in rural areas to supply pockets of 4.16 kV that have not been converted to 27.6 kV.

There are some disadvantages of using Ratio Banks compared to distribution substations, including the following:

- Ratio banks increase system complexity because they result in scattered load serving centers, compared to a distribution substation that would provide a concentrated load-serving point.
- Each Ratio Bank installation requires a certain footprint and is typically aesthetically displeasing. This limits the potential locations where they can be deployed.
- Ratio Banks result in higher transformation losses compared to a distribution station.
- Platform-mounted ratio banks have had higher failure rates and result in lower reliability compared with ground-mounted and fenced solutions.
- Contingency options to address equipment failure are typically limited, often requiring complete replacement to fully restore power (i.e. the transformer and feeder redundancy associated with substations isn't included in the design of most ratio banks and downstream lines).

However, Ratio Banks have comparatively low initial costs and quick installation times compared to traditional substations. Accordingly, they provide an economic and flexible means of supplying rural areas with low-density and widely scattered load centres.

Table 4 provides a summary of the ratio banks installed in the Port Colborne service area.

Table 4: Summary of Port Colborne Ratio Banks

Ratio Bank	Year	# of Phases	Source Voltage (kV)[8]	Load Voltage (kV)[4]	kVA
M10RT6	2002	3	27.6KV	4.16KV	750
M11RT1	2003	1	27.6KV	4.16KV	250
M11RT2	2004	1	27.6KV	4.16KV	250
M11RT3	2004	1	27.6KV	4.16KV	250
M12RT1	1997	1	27.6KV	4.16KV	100
M12RT11	1990	1	27.6KV	4.16KV	100
M12RT12	2004	1	27.6KV	4.16KV	100
M12RT14	2004	1	27.6KV	4.16KV	167
M12RT17	2002	1	27.6KV	4.16KV	167
M12RT4	2003	3	27.6KV	4.16KV	750
M12RT5	2004	3	27.6KV	4.16KV	750
M12RT7	1997	1	27.6KV	4.16KV	167
M12RT8	1983	3	27.6KV	4.16KV	750
M9RT16	1993	3	27.6KV	4.16KV	750
M9RT3	2001	1	27.6KV	4.16KV	100

[8] Voltages are listed in the table as the nominal phase-to-phase voltage and are all wye-connected. For single-phase ratio banks, phase-to-neutral connection voltages are 16.0 kV (Source) and 2.4 kV (Load).

2.4 GANANOQUE DISTRIBUTION SYSTEM

2.4.1 SYSTEM CONFIGURATION AND VOLTAGE LEVELS

A map of the Gananoque distribution system can be found in Appendix A2.

The electricity supply to CNPI in Gananoque originates at the Hydro One 44kV subtransmission system. The territory is supplied from a single Hydro One 44kV feeder that is stepped down to a 16/27.6 kV wye voltage level at CNPI's EOP Main Substation (26.4 kV delta prior to 2017).

The 27.6 kV wye system supplies three customer-owned transformer stations (larger industrial customers), three distribution substations that supply 2.4/4.16 kV wye feeders, four 16.0 kV-2.4 kV (single-phase) ratio banks, and also connects to five customer-owned embedded hydroelectric generating plants. Following the 2017 conversion of the 26.4 kV delta system to 27.6 kV wye, strategic opportunities for 4.16 kV to 27.6 kV voltage conversion are in progress to optimize substation investments and to address performance and/or contingency issues.

2.4.1.1 44 KV SUPPLY TO MAIN SUBSTATION

CNPI normally receives its 44 kV supply in Gananoque from Hydro One's Frontenac TS M8 44 kV feeder. This feeder runs over 35 km radially from Kingston to Gananoque, and prior to 2017 had no ability to be supplied from alternative feeders during contingencies.

In 2017, CNPI worked with Hydro One to complete significant end of life pole replacements to improve the reliability of the M8 feeder, as well as to install 44 kV tie-switches at the approximate mid-point of the M8 feeder. While the 44 kV supply is not fully redundant, it now has a much lower outage frequency, and has an alternative supply option during many contingency scenarios. Further details of this effort are provided in CNPI's 2022-2026 DSP.

2.4.1.2 16/27.6 KV WYE

The 27.6 kV wye system serves as the higher-voltage distribution, or trunk distribution system, in Gananoque. It was originally introduced as 26.4 kV delta to efficiently supply distribution substations, larger load centers, and widely scattered rural loads. Following the delta to wye conversion, the 27.6 kV system continues to provide the same function as the original 26.4 kV delta system, and also presents opportunities for 4.16 kV to 27.6 kV voltage conversion in certain areas. Strategic voltage conversion is being used to:

- Reduce 4.16 kV load in certain areas to a level that optimizes substation investments
- Address specific system performance and contingency issues
- Coordinate end of life asset replacement with voltage conversion

The 27.6 kV system is shown in red in Appendix A2. Three 27.6 kV feeders originate from the Main Substation, and these feeders serve the entire load in Gananoque. The 27.6 kV system serves three distinct components: the “Town Loop”, the “West Line” and the “North Line” as described below.

TOWN LOOP

The Town Loop supplies the bulk of the Town of Gananoque’s urban commercial and residential load by supplying power to the downtown distribution substations – Herbert Street DS and Gananoque DS.

The Town Loop originates at the Main Substation and runs along two separate paths generally referred to as the “East side” and the “West side”. The East side route follows highway and street right-of-ways, while the West side route follows an abandoned Canadian National Railway right-of-way into the Town. Both the East side and West side of the loop eventually make their way to Gananoque DS where they are tied together providing a redundant supply to the substation as well as any additional taps/loads along their path.

THE WEST LINE

The West Line is a 23-kilometre long radial 27.6 kV distribution line that runs west from the Town of Gananoque, along Highway 2. The West Line supplies four ratio banks along the way – Leaky Creek, Ratio Bank #1, and Ratio Bank #2, and Kinston Mills – which step the voltage down to 2.4/4.16 kV for distribution to rural customers in this area. An embedded hydro-electric generator, Kingston Mills Generating Station, also feeds into the West Line.

The 27.6 kV West Line is underbuilt over its entire length with a 4.16kV line that is supplied at different sections from one of the aforementioned ratio banks. Being radially fed, faults along the West Line must be isolated and repaired before power can be restored to customers. Depending on the location of the fault, varying numbers of customers would be affected.

THE NORTH LINE

The North Line is a 38.5-kilometre long radial 27.6 kV distribution line that runs from the Main Substation North to three embedded hydro-electric generating plants and a few residential customers.

Most of this line was constructed in the 1940’s and the conductor size over the majority is #2 copper that is in deteriorating condition. The route of the line is well away from the road, running cross-country through fields and forested areas. Much of the line is inaccessible by vehicular traffic, causing operational challenges. The inaccessibility of the line and the forested environment for much of its length complicates ongoing operation and maintenance, as well as outage restoration. Because the line is a radial configuration with no interties to other feeders, faults must be isolated and repaired before power can be restored to customers.

Capital investments to rebuild portions of the North Line started in 2018. The primary focus of these investments is to rebuild the most deteriorated portions of the line. As rebuild progress, CNPI will investigate the possibility of relocating portions of the line to the road side to improve access.

2.4.1.3 2.4/4.16Y WYE

The 4.16kV distribution system is shown in magenta in Appendix A2. The 4.16kV system in Gananoque is a traditional 2.4/4.16kV grounded-wye system that serves mostly commercial and residential loads in the urban and rural areas.

At present, there is a limitation on the number and capacity of feeder interties in the urban 4.16kV distribution system. Consequently, there is no capability to supply the peak load of one of the downtown distribution stations (Gananoque or Herbert Street) should the second distribution substation be offline under planned or emergency circumstances.

Much of the downtown core contains assets at or near end of life. Significant capital investments will be required over the foreseeable future years to replace/rebuild these assets.

The 4.16 kV system presents some challenges with respect to performance and efficiency. Some challenges are that there is limited capacity on any given feeder due to constraints on voltage drop and conductor size. This poses challenges when connecting large loads and typically requires an extension of the 27.6 kV system (depending on location) in order to connect these loads.

Inefficiencies can also be seen on the 4.16 kV system as the lower system voltage results in line losses. As discussed in the previous section, the conversion of the previous 26.4 kV delta system to 27.6 kW wye, provide opportunities for strategic voltage conversion.

2.4.2 DISTRIBUTION SUBSTATIONS AND STEP-DOWN RATIO BANKS

CNPI's EOP Main Substation provides the transformation and switching required to supply CNPI's 27.6 feeders from Hydro One's 44 kV subtransmission system. All other distribution substations and ratio banks in Gananoque supply 2.4/4.16 kV wye feeders from connections to the 27.6 kV system.

Recent investments have focused on the work required at the EOP Main Substation to complete the 26.4 kV delta to 27.6 kV wye voltage conversion, as well as installing a new ratio bank to retire Kingston Mills DS. Future investments will focus on retiring Gananoque DS, as described in CNPI's 2022-2026 DSP.

Table 5: Summary of Gananoque Distribution Substations and Ratio Banks (RB)

Station	Voltage	# of Transformers	Transformer Age	Total Capacity (MVA)[9]	# of Feeders
Main DS	44-27.6 kV	2	2006, 2017	66	3
Herbert DS	27.6-4.16 kV	1	1992	6	3
Gananoque DS	27.6-4.16 kV	2	1956, 1995	10	6
Leaky Creek RB	27.6-4.16 kV	1 bank of 3	2013	1	2
RB #1	27.6-4.16 kV	1 bank of 3	2013	1	2
RB #2	27.6-4.16 kV	1 bank of 3	2013	1	2
Kingston Mills RB	27.6-4.16 kV	1 bank of 3	2016	1	2

2.4.2.1 EOP MAIN SUBSTATION

The EOP Main Substation serves as the point of supply from Hydro One's 44kV subtransmission system, where two power transformers step the voltage down to 27.6 kV. It contains two 44-27.6 kV transformers, tie switches on the 27.6 kV bus, and three 27.6 kV feeders. As such, all system load can be readily restored following an outage to any single piece of equipment. The station is however susceptible to loss of supply on the incoming 44 kV feeder. Assets in this station are relatively new and in good condition.

2.4.2.2 HERBERT DS

Herbert DS is the newer of the two remaining 27.6-4.16 kV substations. It is located in the northeast corner of Gananoque, serving as the normal supply for the northern and eastern portions of the downtown distribution system. This station is supplied by a radial 27.6 kV tap, and contains a single power transformer. As a result, any sustained outage to the supply feeder or transformer requires 4.16 kV load to be transferred to the Gananoque DS, resulting in system performance issues under certain loading conditions.

2.4.2.3 GANANOQUE DS

Gananoque DS is located in the downtown core of Gananoque where it transforms supply from the 27.6 kV loop to 4.16kV. With six distribution feeders, Gananoque DS serves as the normal point of supply for the South and West portions of the downtown distribution system. It is configured with two 5MVA transformers operating in parallel for an effective capacity of 10MVA. Should one of the power

[9] These numbers represent the sum of the highest nameplate rating (i.e. the fan-cooled rating where applicable) of all transformers.

transformers become unavailable, 4kV load may be transferred as necessary to Herbert Street DS to avoid overloading the remaining transformer.

The two power transformers are in fair and very poor condition, and a number of other assets are at end of life. CNPI's 2022-2026 DSP describes work in progress to install distributed padmount 27.6-4.16 kV transformation throughout the downtown core that will allow this substation to be retired and significantly improve the performance and reliability of the 4.16 kV system.

2.5 SUMMARY OF MAJOR DISTRIBUTION ASSETS

2.5.1 DISTRIBUTION LINE ASSETS

Table 6: Summary of Distribution Line Assets

Asset	Niagara Area	Gananoque Area	Total CNPI
Poles	20,516	2,951	23,467
Pole-Top Transformers	3,249	546	3,795
Pad-Mount Transformers	572	76	648
Ratio Banks Transformers[10]	94	4	98
Line Reclosers	35	1	36
Voltage Regulators	8	-	8
Primary Overhead Line KM	765	171	936 km
Primary Underground Line KM	88	13	101 km

2.5.2 DISTRIBUTION SUBSTATION ASSETS

Table 7: Summary of Major Substation Equipment

Asset	Niagara Area	Gananoque Area	Total CNPI
Power Transformers	15[11]	5	20
Circuit Breakers	50	14	64
Protection Relays	22	7	29
Battery Banks	9	3	12
Substation Viper Recloser	20	3	23
Other Substation Protection[12]	22	-	22

[10] The ratio bank counts in this table include the total number of transformers, which is be higher than the counts indicated in the METSCO ACA report. The ACA report assessed the condition of each installation rather than each individual transformer.
[11] This number represents in-service power transformers that are distribution assets. The METSCO ACA report shows 19 power transformers, which includes one spare transformer, and three 115-34.5 kV transformers owned by CNPI that are transmission assets and therefore excluded from this AMP document.
[12] Includes sets of power fuses, metal-clad switchgear installations, and SF_6 circuit interrupters.

2.5.3 METERING ASSETS

Table 8: Summary of Metering Assets

Asset	Niagara Area	Gananoque Area	Total CNPI
Tower Gateway Base (TGB) Stations	3	2	5
AMI Repeaters	-	1	1
AMI Meters (Smart Meters)	25,988	3,559	29,547
Interval/MIST Meters	165	26	191
Meter Installations with Secondary Instrument Transformers	623	158	781
Meter Installations with Primary Instrument Transformers (Excl Wholesale)	35	3	38
Wholesale Meters	16	-	16
Wholesale Meter Installations	8	-	8

3 DISTRIBUTION SYSTEM ASSETS

3.1 ASSETS CATEGORIES

CNPI's distribution assets can be broken down into various categories and definitions:

- **Financial (Fixed) Asset:** This is the traditional accounting/finance view of assets, included in various accounts and focusing on financial information such as original cost, current book value, and depreciation amounts.
- **Physical Assets (Components):** This is the traditional operations view of assets, which are actual material parts such as a 45 foot class 4 wood pole, a cross-arm, or a section of 28kV underground primary cable.
- **Managed Asset:** For purposes of the CNPI AMP, a Managed Asset (MA) is an assembly of one or more components tracked and managed as a single entity. For example a single 'Pole' MA might consist of the pole itself in addition to any supporting components such as guy wires and anchors. A framing MA may contain a cross-arm, three 28kV insulators, plus the sundry other approved hardware required.

CNPI's AMP will focus almost entirely on Managed Assets as the effective meaning of 'assets' in the context of this document.

3.2 OVERHEAD AND UNDERGROUND DISTRIBUTION MANAGED ASSETS

3.2.1 POLES

Poles constructed of wood and occasionally resin composites, these form the 'backbone' of the overhead distribution system. Wooden poles are used in over 98 percent of all cases. The poles used in CNPI's distribution systems generally range in height from 25' (7.6 m) to 75' (22.8 m). A typical height for a single-circuit three-phase pole is 45' (13.7 m). Poles come in several standard 'strengths' known as classes, as defined by CSA specifications.

3.2.2 FRAMING ASSEMBLIES

This MA is the assorted hardware components installed on a pole or structure that provide mechanical support and clearances, and electrical isolation / insulation for the various conductors and equipment required on an overhead distribution line.

It can include cross arms, insulators, brackets, bolts, washers, nuts, and sundry other hardware.

It should be noted that the specific choice of some of these components, such as insulators, will vary depending on the required voltage of the system.

3.2.3 TRANSFORMERS AND VOLTAGE REGULATORS

Distribution transformers are used to transform electricity from primary to secondary voltage levels, for example, from 16 kV to 120/240 Volts. Overhead (Pole Top) transformer capacity in use at CNPI typically ranges from 3 to 167 kVA.

Most distribution transformers change primary voltage (2.4 kV or greater) to one of the three standard secondary voltages:

1) 120/240V single phase
2) 120/208V three phase
3) 347/600V three phase

Some specialized units, known as step-downs or ratio banks, transform one primary voltage to another. These units are generally used to supply portions of CNPI's system operating at voltage levels other than those supplied from CNPI's substations as further detailed in Section 2 of this document.

Voltage regulators are a form of transformer that automatically maintains line voltages within a specified range and allows CNPI to maintain voltages within CSA standard guidelines on long feeders or feeders with larger than typical loads.

3.2.4 OVERHEAD SWITCHES

This type of MA allows for opening and closing, or isolating, of current-carrying components, which either prevents or allows the flow of electricity. Switches can have different characteristics:

1) Gang-operated or single-phase operated: A gang-operated switch, generally a three-phase device, allows all three phases of the switch to be opened or closed at once, often from the ground. Single-phase switches are typically operated using insulated sticks, and are operated one phase at a time.
2) Load-break or Non-load-break: A Load-break switch allows for the interruption of power flow even when a significant amount of current is flowing. Non-load-break switches cannot interrupt large current flows and are more often used in combination with nearby protective devices for providing visual confirmation of isolation.
3) Remote-controlled or locally operated.
4) Dielectric: the medium used by the switch to interrupt or insulate can vary. Most use air (such as the 'Cutouts' in the picture), while others use oil, vacuum, or SF_6.

3.2.5 OVERHEAD CONDUCTOR

Conductors, also called wires, or cables run from pole to pole, or pole to building, and carry the current from the source to the customers. Overhead conductor has several different characteristics:

1) Metal or alloy: older overhead distribution conductors were mostly copper, but most modern applications use aluminum, or aluminum alloys to save weight and cost.
2) Size / Gauge: the size of the wire is matched to at least the expected maximum current, with additional consideration of mechanical and electrical performance. Larger conductors cost more, weigh more, and can take longer to install, but carry more current and can have longer useful lives.
3) Insulation: some conductors have one or more layers of insulation on them, if they are bundled together or are installed in a location where they can be expected to be contacted by vegetation or the public. Most secondary conductors and bundled and insulated since insulation requirements are minimal at lower voltage levels. Conversely most primary / high voltage conductors are bare, as this saves costs and weight.
4) Single or Bundled: At lower voltages, to save space and add strength, more than one conductor may be twisted or lashed into a 'bundle'. This is most common for secondary or service wires.

3.2.6 PROTECTIVE AND SYSTEM DEVICES

Protective and system device are aggregated into the following MA groups:

1) Reclosers (a type of aerial circuit breaker), used to detect faults, sectionalize feeder to isolate faulted equipment, and increasingly for distribution automation schemes
2) Primary (pole-mounted) instrument transformers or sensors
3) Fuses used for equipment protection (e.g. pole-top transformers and ratio banks)

3.3 UNDERGROUND DISTRIBUTION MANAGED ASSETS

3.3.1 PAD-MOUNTED TRANSFORMERS

Used to transform electricity from one voltage to another in surface-mount applications. These devices range in sizes from 37.5kVA to 100kVA in residential subdivisions and from 75kVA to 1000kVA in commercial installations.

This type of transformer incorporates integral protection elements typically consisting of a bay-o-net style fuse with a partial range current limiting back up fuse. The transformer also typically incorporates primary winding and bushing isolation switches.

3.3.2 SWITCHGEAR

Pad-mounted switchgear are used in underground applications to provide a point of switching and or circuit protection. The installations contain provisions for terminal connection of up to four sets of cables.

Each of the four terminal connection points or “ways” can incorporate either a load break disconnecting switch or a protection element (power fuse or interrupter).

Electrical insulation within the switchgear enclosure is achieved by air or SF_6 gas.

3.3.3 CIVIL STRUCTURES

This MA group consists of:

1) Foundations / Pads
2) Manholes
3) Vaults
4) Conduit

3.3.4 PRIMARY CABLE

Primary cables are typically installed for feeder cable exits in substations, and commercial or residential subdivisions with underground servicing. These cables are built to CSA Standard C68.5 and consist of a copper or aluminum phase conductor with a copper stranded concentric neutral conductor.

Sizes of conductor range from 1/0 to 1000 kcmil. Modern cables are typically insulated with cross linked polyethylene (XLPE) with a linear low-density polyethylene (LLDPE) jacket.

3.3.5 SECONDARY CABLE

Secondary cables are used to supply low voltage (<=600V) to customers from a distribution transformer. These cables typically range in size from #6 to 1250 kcmil and can be aluminum or copper.

The conductors can be directly buried or installed in conduit. They can also be bundled to save space and simply the installation methodology.

3.4 DISTRIBUTION SUBSTATION MANAGED ASSETS

3.4.1 POWER TRANSFORMERS

Power transformers installed in distribution substations are used to transform electricity from a higher primary voltage (such as 34.5kV) to a lower primary voltage (such as 8.32kV).

Power transformers in CNPI’s distribution stations are all 3-phase, with capacities in CNPI’s distribution substations ranging from 3 MVA to 33 MVA.

Conductor terminal connections are established with either overhead exposed conductor, underground cable in an enclosed compartment or a combination of both.

Integral to the power transformer are components such as insulated bushings, cooling systems, gauges, tap changing equipment, etc. that require routine inspection and maintenance.

Power transformers are much larger than pole top transformers. These units typically weigh several thousand kilograms and contain thousands of litres of oil. As a result, they must be placed on engineered concrete foundations.

3.4.2 PROTECTIVE AND SWITCHING DEVICES

3.4.2.1 CIRCUIT BREAKERS

Many of CNPI's distribution station assets and feeders are protected by relay-controlled circuit breakers. Circuit breakers are rated from 5kV to 35.4kV and are situated in switchgear or outdoor structures.

Breakers are designed to clear overcurrent, differential, and distance faults with response times ranging from three to eight cycles. Breakers are insulated with either air, oil, or SF6.

Isolation devices are typically installed to permit these devices to be removed from service for maintenance or replacement.

3.4.2.2 RECLOSERS

Solid dielectric three phase reclosers have been introduced into many of CNPI's newer distribution stations to provide transformer and feeder protection. These devices incorporate vacuum interrupters with reduced maintenance requirements as compared to circuit breakers.

The devices are designed for applications at 4.16kV through to 34.5kV and have continuous current carrying capability in excess of 600A. These devices are relay controlled and can be supplied from DC station service systems. Fault response times are typically in the range of five to eight cycles.

Reclosers can be pole or structure mounted and are also available in a pad-mounted configuration.

3.4.2.3 POWER FUSES

Power fuses were historically used to provide primary overcurrent protection for smaller power transformers in distribution substation. These devices have many limitations in comparison to other forms of protection, including potential for single-phasing, inability to assess fault levels/location, and inability to monitor or operate the device remotely. CNPI stocks spare fuse elements for its remaining in-service substation power fuses, but has been gradually phasing these devices out during substation rebuilds and refurbishments.

3.4.2.4 METAL-CLAD SWITCHGEAR

Substation metal-clad switchgear located in CNPI's DS locations typically contains multiple cells (or compartments) which house protection elements such as breakers or fuses. The cells may also contain instrument transformers for metering or relaying requirements.

Protection elements incorporated into DS switchgear are for the purposes of feeder, bus, or transformer protection.

Metal-clad switchgear can be located in an indoor building or an outdoor environment.

3.4.2.5 SUBSTATION SWITCHES

Where switching functionality is required for visual isolation or making system configuration changes, overhead switches similar to those described in Section 3.2.4 can also be deployed inside substations. May of these types of switches are available in standard substation configurations that are suitable for mounting on steel structures instead of wood poles.

3.4.3 GROUNDING SYSTEM AND LIGHTNING PROTECTION

Substation grounding systems consist of a network of buried electrodes interconnected by buried conductors forming a "grounding grid". Conductive structures and equipment throughout the substation are connected directly to this buried grid.

Lightning masts and/or shield wires are installed to provide protection against direct lightning strikes. Also, lightning arresters are typically installed adjacent to power transformers and other critical equipment. The main functions of the grounding and lightning protection system are:

1) To protect equipment by providing a means of carrying electric currents into the earth under normal and fault conditions.
2) To limit over-voltage at equipment terminals during lightning discharges.
3) To protect personnel in the vicinity of grounded equipment from critical shocks by limiting step and touch potentials to acceptable values.

3.4.4 SUBSTATION CIVIL/STRUCTURAL ASSETS

These assets generally support the installation and security of the electrical assets described above, and are aggregated into the following groups:

1) Steel Structures
2) Concrete Foundations
3) Fencing
4) Yard Surfacing
5) Cable Trays/Ducts

3.4.5 BATTERY BANKS

Substation battery banks provide DC control power to protection, control and communication equipment, and often provide emergency backup power to other essential systems during a loss of supply to the substation.

3.5 SCADA AND COMMUNICATIONS EQUIPMENT

CNPI leverages a mature Supervisory Control and Data Acquisition (SCADA) system which provides monitoring of CNPI's substation elements and field automation devices. The SCADA system uses communication mediums such as leased telephone line, spread spectrum radio, and fiber optics for connectivity with endpoint devices. The SCADA system is integral to CNPI operations and provides real time access and control of critical infrastructure improving response and restoration times. Endpoint deployment continues as part of CNPI's distribution automation program in order to mitigate feeder performance issues.

3.6 METERING MANAGED ASSETS

Metering assets support the accurate recording of electrical energy withdrawn from CNPI's distribution systems, as well as the automated transmission and aggregation of metering data for billing and operational purposes. MA include the following asset types:

1) Revenue meters that measure, store and report electricity usage
2) Instrument transformers
    a. current transformers (CTs)
    b. potential or voltage transformers (PTs)
3) All communications or data aggregation equipment owned by CNPI used to facilitate the revenue metering process (collectors, antennae, modems, etc.)

4 INSPECTION AND MAINTENANCE PROGRAMS

The following sections provide a general overview of CNPI's inspection and maintenance programs, followed by detailed descriptions of maintenance activities for specific classes of assets.

4.1 INSPECTION AND MAINTENANCE (GENERAL)

Inspection and maintenance programs are integral aspects of any AMP and good utility practice. Effectively maintaining existing line and substation equipment is necessary to keep equipment in good working condition, maximize equipment lifespan, and improve reliability by reducing the probability of failure. Maintenance programs optimize the value of capital investments. Maintaining equipment in proper working condition reduces the probability of equipment failure, enhances safety and increases reliability of supply to customers.

Maintenance activities at CNPI are performed with a combination of internal personnel and qualified outside contractors and consultants. CNPI establishes its various maintenance cycles to achieve a number of objectives:

1) Maintenance cycles for inspections will satisfy the minimum regulatory requirements where applicable.
2) Critical assets may be inspected more frequently and/or may make use of more sophisticated inspection methods (e.g. thermographic scans at substations, dissolved gas analysis).
3) Preventive maintenance activities are scheduled on cycles that attempt to optimize the life-cycle costs of equipment considering manufacturer's recommendations, good utility practice as well as CNPI past experience.
4) Preventive maintenance activities that are scheduled cycles greater than one year will be scheduled with a goal of levelling expenditures year-to-year. This ensures adequate resource availability to complete the planned annual maintenance programs.

Maintenance activities can be subdivided into four basic categories:

4.1.1 PREDICTIVE MAINTENANCE

Predictive maintenance is the identification of equipment deficiencies that may lead to failure. Examples of predictive maintenance activities are visual inspections, equipment testing, and substation transformer dissolved gas analysis. Thorough visual inspections are the primary mechanism used at CNPI for predictive maintenance, although other methodologies such as non-destructive testing, thermographic scans and dissolved gas analysis are also used for certain assets.

4.1.2 CORRECTIVE MAINTENANCE

Corrective Maintenance is the repair of equipment that resulted from deficiencies identified through visual inspections or testing. Certain alarms triggered in CNPI's SCADA system may also drive corrective maintenance work following visual inspections to confirm the cause of the alarm.

4.1.3 PREVENTATIVE MAINTENANCE

Preventative maintenance involves the routine servicing or repair of equipment on a regular schedule, or following a specified number of operations, to ensure that equipment remains in good working condition. Maintenance is undertaken at specific time intervals and is applied regardless of equipment condition. Examples of preventive maintenance activities are load-break switch maintenance, protective device maintenance, and transformer tap-changer maintenance.

There has been a gradual progression from preventative maintenance to predictive maintenance activities for certain assets in recent years. This trend is a result of technological improvements and cost reductions in predictive maintenance technologies, as well as technological advances in new equipment. An example would be solid-dielectric, vacuum-interrupting reclosers that no longer require periodic oil changes and contact replacement that was essential for the proper operation of oil-filled equipment.

4.1.4 CERTIFICATION MAINTENANCE

Certain assets require periodic certification or re-certification. This generally involves testing, calibration, and documentation (such as a 'seal' or 'sticker') by a third-party accredited or industry-accepted expert group. Examples of managed assets requiring certification:

1) Revenue meters and instrument transformers (residential, commercial / industrial, and bulk)
2) Insulated booms on Bucket Trucks
3) Working grounds used by power line technicians

4.2 LINE MAINTENANCE ACTIVITIES

4.2.1 PREDICTIVE AND CORRECTIVE MAINTENANCE

4.2.1.1 VISUAL INSPECTIONS

All of CNPI's overhead and underground distribution system assets are subject to periodic visual inspections that meet the requirements of Appendix C of the Distribution System Code. The maps provided in Appendix B illustrate CNPI's inspection zones, where inspections for each zone are completed in successive calendar years over a 3-year cycle.

All overhead and underground feeder sections scheduled to be inspected during a given year are patrolled and detailed inspections are carried out on all managed assets. This includes poles, crossarms, guy wires, transformers (overhead and pad-mounted), conductors and cables, insulators, arrestors, bushings, terminations, switching devices (fused cut-outs, load-break and disconnect switches, live-line openers, etc.). Civil facilities, such as transformer pads and cable chambers, are also inspected. Underground facilities are also inspected only where visible (risers, terminations, etc.).

The completion of these inspections and any identified deficiencies are documented for follow-up and are archived. Deficiencies are assessed on the basis of the potential for failure and consequential impact on safety or reliability. They are then prioritized for corrective action as follows:

1) Major deficiencies, where repair or replacement is required to address a pending failure or safety hazard. Examples of major deficiencies would be broken poles and cross-arms.
2) Minor deficiencies, where the deficiency is of a nature where action can be deferred for a time. An example would be a blown lightning arrestor. Repairs to less critical deficiencies are typically planned so that a group of deficiencies within a given area can be addressed by a single crew in a short timeframe.

Any deficiencies observed outside of scheduled line patrols, such as during service work, outage response, or travel to job sites, are also recorded, prioritized and corrected as described above.

4.2.1.2 INSPECTION USING SPECIALIZED EQUIPMENT

THERMOGRAPHIC SCANNING

In addition to the visual inspections described above, various line components are scanned using thermographic cameras during feeder patrols. Abnormal temperatures that might indicate concerns with equipment or connections are noted and prioritized for corrective maintenance as required.

POLE TESTING

In 2011, CNPI performed detailed, non-destructive testing on a random sample comprising approximately 11% of its pole population. The result of this testing provided CNPI with the condition of poles tested, the pole strength, and the expected remaining life of the pole population. The main objective of this program was to estimate the overall condition of CNPI's pole population as an input to CNPI's first DSP, which covered the 2017-2021 period.

In 2016, CNPI implemented a program to perform testing on all of its distribution poles over a multi-year period to inform the pace and priority of line rebuild and pole replacement programs. Over 13,000 poles, representing over half of CNPI's pole population, were tested between 2016 and 2020. Beginning in 2021, CNPI has revised its pole testing scope of work to include the use of mobile tools linked to its GIS system to enhance both the efficiency and accuracy of data collection by pole testing crews. These efforts will also reduce manual effort for CNPI's operations and engineering staff related to data validation and analysis, allowing a greater number of poles to be tested each year.

4.2.2 PREVENTATIVE MAINTENANCE

4.2.2.1 VEGETATION MANAGEMENT

CNPI's Integrated Vegetation Management Program has been developed to align with its Health Safety and Environmental Management System (HSEMS) consistent with ISO 14001 standard, OHSA 18001 standard, the North American Electric Reliability Corporation (NERC) Compliance Program, American National Standards Institute (ANSI) A300 – Standard Practices for Trees, Shrubs and other Woody Plant Maintenance, the Electrical Safety Authority (ESA) Guidelines for Tree Trimming Around Power Lines and Planting Under or Around Power Lines and Electrical Equipment. These management systems, standards and guidelines provide the framework for ensuring adequate processes such as governance and oversight.

CNPI performs its vegetation management in the following manner:

1) 3-year periodic limb and branch removal or trimming along the entire overhead distribution system.
2) Spot trimming or branch removal in any specific areas where faster-than-typical growth has occurred or one or more damaged branches have entered the minimum clearance zone from outside the vegetation control space.

CNPI's 3-year tree trimming cycles are generally aligned with the visual inspection zones discussed in Section 4.2.1.1. The trimming is generally performed by an outside contractor, who must certify completion and no undue hazards on each portion of their work. A CNPI inspector then verifies the work completed.

In areas that are rural in nature, or areas where CNPI-owned distribution lines do not lay on the edge of a municipal right-of-way, the approach is generally to clear-cut a corridor near line assets to allow for longer periods between vegetation control efforts (referred to as "Grubbing"). This is more cost-effective in the long run.

4.2.2.2 SWITCH MAINTENANCE

CNPI maintains switches located in its substations and on its sub-transmission feeders on a 3-year cycle, consistent with cycles for other activities such as feeder inspections and vegetation management. This minimizes the likelihood of widespread outages due to switch failure and ensures that switches will operate reliably in the event of planned or forced outages elsewhere on the system. Switch maintenance includes the following main activities:

1) Visual inspection of switch components, such as contacts, insulators and arc horns, to identify any broken or deteriorated parts and evidence of surface tracking or corrosion.
2) Opening and closing switches to verify proper and efficient operation of blades and gang-operating mechanisms, where applicable.

3) Cleaning and lubrication of electrical connections and moving parts.
4) Replacement of worn components, or the entire switch if necessary.

4.2.2.3 PROTECTIVE DEVICE AND VOLTAGE REGULATOR MAINTENANCE

CNPI performs routine maintenance of its Reclosers, Sectionalizers and Voltage Regulators. Maintenance activities are typically performed on a six-year cycle (or based on manufacturer's recommendation cycle, if more frequent), and include the following main activities:

1) Determination of number of operations since date of last maintenance to verify that existing maintenance intervals are adequate.
2) Visual inspection of tanks, bushings, contacts, operating mechanisms, control boxes, etc. to identify any broken or deteriorated parts and evidence of surface tracking or corrosion.
3) Testing of operations, both manually and using electrical test equipment to ensure proper operation.
4) Electrical testing (ratio, resistance, etc.) to verify electrical integrity of device and all components.

The results of any tests performed are documented on equipment test forms and kept on file for trending and comparison purposes.

4.3 DISTRIBUTION SUBSTATION MAINTENANCE ACTIVITIES (GENERAL)

4.3.1 PREDICTIVE MAINTENANCE

Predictive substation maintenance is integral to maintaining reliability and detecting potential equipment failure. Since substation equipment typically requires large investments for installation and since failure of substation components can affect large numbers of customers, therefore detecting potential failures before they occur is very important. There are presently three key predictive maintenance activities conducted in CNPI substations:

4.3.1.1 VISUAL INSPECTIONS

Visual Inspections are essential for assessing the condition of substation components and identifying deterioration or areas where attention is required. CNPI conducts detailed monthly visual inspections on each of its distribution substations.

Substation civil/ structural (fencing, structures, etc.) and electrical components (bus-work, switches, insulators, transformers, ground conductors, etc.) are inspected and any deficiencies recorded. In addition, data such as relay targets, breaker counters, DC system voltage, and power transformer gauge readings are recorded. The condition of ancillary equipment such as lighting, eyewash stations, first-aid kits, and oil spill kits is also inspected.

CNPI also performs monthly inspections of its oil containment facilities and sampling of effluent from the oil containment in accordance with Ministry of Environment, Conservation and Parks requirements.

Any deficiencies noted during inspections are recorded, reported, and are then prioritized for corrective action.

4.3.1.2 TRANSFORMER AND DISSOLVED GAS ANALYSIS

Dissolved gas analysis (DGA) is an effective tool for assessing the condition of power transformers and identifying deterioration in transformer oil or insulation. DGA can also identify whether arcing or acid build up is occurring inside the transformer. DGA tests for the presence of dissolved gas and water in transformer insulating oil, and based on the level of gases or moisture present, assess the condition of the transformer. An important aspect of DGA is the trend analysis, which reviews the history of dissolved gas levels in the transformer.

DGA is scheduled at least annually on all power transformers and in CNPI substations, whether in-service or spare. CNPI uses qualified contractors to perform the analysis, provide reports on transformer condition, and recommend any required actions if gassing is above normal levels or if acids are detected. Corrective action to deal with abnormalities is essential to prevent failure and extend the life of the transformer.

4.3.1.3 THERMOGRAPHIC SCANNING

Thermographic (infra-red) scanning is scheduled annually for all distribution substations. Thermography captures the temperature of components compared to surrounding equipment and ambient temperature, and high relative temperatures can be indicative of overloaded or deteriorated components.

4.3.2 CORRECTIVE MAINTENANCE

Corrective maintenance is a reactive activity that takes place when deficiencies in substation components are identified. Defective components are prioritized for repair or replacement on the basis of the severity of the condition, the criticality of the equipment, and the potential impact of failure on safety or service reliability.

4.3.3 PREVENTATIVE MAINTENANCE

Preventive maintenance on substation components is conducted on a regularly scheduled basis and is integral to keeping equipment in good working condition. Substation components typically undergo preventive maintenance on a 6-year cycle, including inspecting, cleaning, lubricating, and testing. The following major activities are included in this program:

1) Transformers (power and instrument) – inspection and cleaning, tap-changer maintenance, Doble testing, oil refurbishment as required, inspection and cleaning of gauges, access ways, bushings, and connections.
2) Breaker / Recloser / Switchgear maintenance – inspection, cleaning of bushings, connections, contacts and moving parts, contact resistance and insulation testing.
3) Switch maintenance – inspection and cleaning of bushings, connections, contacts, arc horns, and operating mechanisms, insulation testing.
4) Relays and SCADA systems – testing to ensure appropriate response, and recalibration of electronic and electromechanical relays as required.
5) Oil renewal – replacing insulating oil in power transformers and oil-insulated circuit breakers and potential transformers as needed ensuring insulating oil is clear of contaminants.
6) Accessories – other equipment such as motor operators and heating elements are inspected, cleaned, and maintained.

4.4 SUBSTATION EQUIPMENT MAINTENANCE METHODOLOGIES (TYPE-SPECIFIC)

4.4.1 PREDICTIVE MAINTENANCE

4.4.1.1 POWER TRANSFORMERS

1) Inspect transformer tanks and fittings for signs of oil leaking/weeping.
2) Inspect all gauges and record readings.
3) Inspect bushings for cracks and contamination.
4) Record on-load tap changer counts and ranges, and reset sweep arms (if applicable).
5) Record any new and/or unusual noise.
6) Verify manual operation of cooling fans (if applicable).

4.4.1.2 OVERHEAD SWITCHES

1) Inspect the insulators for breaks, cracks, burns, or cement deterioration. If necessary clean the insulators particularly where abnormal conditions such as salt deposits, cement dust, or acid fumes exist. This is important to minimize the possibility of flashover as a result of the accumulation of foreign substances on the insulator surfaces.
2) Inspect all live parts for scarring, gouging, or sharp points that could contribute to excessive radio noise and corona.
3) Check for damaged fuses (where applicable) and replace if necessary
4) Scan the switch with an infrared scanner to check for further defects

4.4.1.3 UNDERGROUND SWITCHES AND JUNCTION UNITS

1) Scan the switch with an infrared scanner to check for defects

4.4.1.4 SURGE ARRESTERS

1) Check for cracked, contaminated, or broken porcelain; loose connections to line or ground terminals; and corrosion on the cap or base.
2) Check for pitted or blackened exhaust parts or other evidence of pressure relief.

4.4.1.5 BUSES AND SHIELD WIRES

1) Inspect bus supports for damaged porcelain and loose bolts, clamps, or connections.
2) Observe the condition of flexible buses and shield wires.
3) Inspect suspension insulators for damaged porcelain (include line entrances).

4.4.1.6 STRUCTURES

1) Inspect all structures for loose or missing bolts and nuts.
2) Observe any damaged paint or galvanizing for signs of corrosion.
3) Inspect for deterioration, buckling, and cracking.

4.4.1.7 GROUNDING SYSTEM

1) Check all above-grade ground connections at equipment, structures, fences, etc.
2) Observe the condition of any flexible braid type connections.

4.4.1.8 CONTROL AND METERING EQUIPMENT

1) Check current and potential transformers for damage to cases, bushings, terminals, and fuses.
2) Verify the integrity of the connections, both primary and secondary.
3) Observe the condition of control, transfer, and other switch contacts; indicating lamps; test blocks; and other devices located in or on control cabinets, panels, switchgear, etc. Look for signs of condensation in these locations.
4) Examine meters and instruments externally to check for loose connections and damage to cases and covers. Note whether the instruments are reading or registering.
5) Check the status of relay targets (where applicable).
6) Make an external examination of relays, looking for damaged cases and covers or loose connections.
7) Observe the ground detector lamps for an indication of an undesirable ground on the dc system.
8) Check voltage levels on battery bank components and check electrolyte levels in individual batteries where applicable.
9) Check the annunciator panel lights.

4.4.1.9 METAL-CLAD SWITCHGEAR

1) Inspect for damage to enclosures, doors, latching mechanisms, etc.
2) Inspect bus supports for signs of cracking.

3) Verify that all joints are tight.
4) Check the alignment of all disconnect devices, both primary and secondary, including those for potential transformers.
5) Inspect terminal connections and the condition of wiring.
6) Check rails, guides, rollers, and the shutter mechanism.
7) Inspect cell interlocks, cell switches, and auxiliary contacts.
8) Inspect control, instrument, and transfer switches.
9) Inspect for broken instrument and relay cases, cover glass, etc, and check for burned out indicating lamps.

4.4.1.10 CABLES

1) Inspect exposed sections of cable for physical damage.
2) Inspect the insulation or jacket for signs of deterioration.
3) Check for cable displacement or movement.
4) Check for loose connections.
5) Inspect shield grounding (where applicable), cable support, and termination.

4.4.1.11 FOUNDATIONS

1) Inspect for signs of settlement, cracks, spalling, honeycombing, exposed reinforcing steel, and anchor bolt corrosion.

4.4.1.12 SUBSTATION AREA-GENERAL

1) Verify the existence of appropriate danger and informational warning signs.
2) Check indoor and outdoor lighting systems for burned-out lamps or other component failures.
3) Verify that there is an adequate supply of spare parts and fuses.
4) Inspect all fire protection, draining and oil containment systems in accordance with operating manuals.
5) Check for bird nests or other foreign materials near energized equipment, buses, or fans.
6) Observe the general condition of the substation yard, noting the overall cleanliness and the existence of low spots that may have developed.
7) Observe the position of all circuit breakers in the auxiliary power system and verify the correctness of this position.
8) Inspect the area for weed growth, trash, and unauthorized equipment storage.

4.4.1.13 SUBSTATION FENCE

1) Check for minimal gap under the fence or under the gate. Ensure that all gaps are less than 50 mm at any point under the fence and less than 100 mm at any point under the gate.
2) Ensure the fence fabric is intact and document any areas with significant rust or corrosion.

3) Ensure fence fabric, gates, tension wires, barb wire, and posts are adequately bonded and effectively grounded.
4) Check that the barbed wire is taut.
5) Ensure the gate latches are operable.
6) Ensure flexible braid-type connections are intact.
7) Ensure fence is clear of obstructions such as vegetation grow-ins or other objects (e.g. wind-blown trash)
8) Verify that no adjacent wire fences are tied directly to the substation fence.

4.4.2 PREVENTATIVE MAINTENANCE METHODOLOGIES

4.4.2.1 BLADE (BLD) OR INLINE SWITCHES (NON-GANG OPERATED)

1) Open/Close the switch several times, periodic operation of the switch is recommended as this ensures the hinge pivot point is operating smoothly and helps clean any oxide from the jaw contacts, which may have formed since the last maintenance.
2) Check for proper switch blade seating in the closed position.
3) Check the switch for alignment, contact pressure, eroded contacts, corrosion, and mechanical malfunction.
4) Inspect the insulators for breaks, cracks, burns, or cement deterioration. If necessary, clean the insulators, particularly where abnormal conditions such as salt deposits, cement dust, or acid fumes exist. This is important to minimize the possibility of flashover as a result of the accumulation of foreign substances on the insulator surfaces.
5) Inspect all live parts for scarring, gouging, or sharp points that could contribute to excessive radio noise and corona.
6) If the switch blade has been left open for an extended period of time, if necessary the jaw and blade contacts should be wiped clean of any dirt particles to ensure that there will be no plating damage to the contacts and that they will properly mate. If necessary thinners or acetone may be used to clean the contacts and if the contacts are heavily coated use a fine Scotch-Brite® pad.
7) Scan the switch with an infrared scanner to check for further defects.
8) Refer to any additional maintenance instructions or manufacturer recommendations attached to work orders.

4.4.2.2 GANG-OPERATED SWITCHES

1) The switch should be disconnected from all electric power sources before servicing.
2) Ground leads or their equivalent should be attached to both sides of the switch; local and applicable OSHA regulations should be followed.
3) Inspect the insulators for breaks, cracks, burns, or cement deterioration. Clean the insulators particularly where abnormal conditions such as salt deposits, cement dust, or acid fumes exist.

This is important to minimize the possibility of flashover as a result of the accumulation of foreign substances on the insulator surfaces.

4) Check the switch for alignment, contact pressure, eroded contacts, corrosion, and mechanical malfunction. Replace damaged or badly eroded components. If contact pitting is of a minor nature, smooth the surface with clean, fine sandpaper (not emery) or as the manufacturer recommends. If recommended by the manufacturer, lubricate the contacts.
5) Inspect arcing horns for signs of excessive arc damage and replace if necessary.
6) For all S&C Alduti-Rupter switches perform the outlined continuity check and additional maintenance as out lined in the Alduti-Rupter Switch, General-Maintenance Outline.
7) Check the blade lock or latch for adjustment.
8) Inspect all live parts for scarring, gouging, or sharp points that could contribute to excessive radio noise and corona. If applicable, check corona balls and rings for damage that could impair their effectiveness.
9) Inspect inter phase linkages, operating rods, levers, bearings, etc., to assure that adjustments are correct, all joints are tight, and pipes are not bent. Clean and lubricate the switch parts only when recommended by the manufacturer. Check for simultaneous closing of all blades and for proper seating in the closed position. Check gear boxes for moisture that could cause damage due to corrosion or ice formation. Inspect the flexible braids or slip-ring contacts used for grounding the operating handle. Replace braids showing signs of corrosion, wear, or having broken strands.
10) Power-operating mechanisms for switches are usually of the motor-driven, spring, hydraulic, or pneumatic type. The particular manufacturer's instructions for each mechanism should be followed. Check the limit switch adjustment and associated relay equipment for poor contacts, burned out coils, adequacy of supply voltage, and any other conditions that might prevent the proper functioning of the complete switch assembly.
11) Inspect overall switch and working condition of operating mechanism. Check that the bolts, nuts, washers, cotter pins, and terminal connectors are in place and in good condition. Replace items showing excessive wear or corrosion. Inspect all bus cable connections for signs of overheating or looseness.
12) Inspect and check all safety interlocks while testing for proper operation.
13) Refer to any additional maintenance instructions or manufacturer recommendations attached to work orders.

4.4.2.3 OIL CIRCUIT BREAKERS

1) Check compressor operation, including operation of all pneumatic switches and their operating set point.
2) Check for air leaks.
3) Check the compressor belts.
4) Check the latching mechanisms, relay contacts, and fuse clips (for secureness).

5) Check pole units, contacts, bayonets, interrupters, and resistors for signs of heating.
6) Inspect the hardware and wiring connections for Current Transformers (CTs).
7) Inspect the alignment of contacts.
8) Inspect the operating mechanism and leakage.
9) Inspect the lift rod and toggle assembly.
10) Check for loose, contaminated, or damaged bushings; loose terminals; oil leaks; and proper gas pressures.
11) Check the oil level in bushings and the main tank (if applicable).
12) Check the anti-condensation heaters.
13) Read and record the number of operations indicated. If the breaker has not operated during the preceding year, bypass the breaker or otherwise take it out of the circuit for testing.
14) Inspect contact areas on the main plug-in assembly for signs of overheating or arcing.
15) Read and record compressor operating hours as shown on the indicator.
16) Refer to any additional maintenance instructions or manufacturer recommendations attached to work orders.

4.4.2.4 AIR BLAST AND SF_6 CIRCUIT BREAKERS

1) Check compressor operation, including operation of all pneumatic switches and their operating set point.
2) Check for air leaks.
3) Check the compressor belts.
4) Check the latching mechanisms, relay contacts, and fuse clips (for secureness).
5) Check pole units, contacts, bayonets, interrupters, and resistors for signs of heating.
6) Inspect the hardware and wiring connections for CTs.
7) Inspect the alignment of contacts.
8) Inspect the operating mechanism and leakage.
9) Inspect the lift rod and toggle assembly.
10) Inspect the compressor system, including belts, pneumatic switches, contactors, relays, and other auxiliary devices.
11) Inspect the gas or air piping for signs of deterioration.
12) Inspect all air or gas seals and o-rings.
13) Check for loose, contaminated, or damaged bushings; loose terminals and proper gas pressures.
14) Check the anti-condensation heaters.
15) Read and record the number of operations indicated. If the breaker has not operated during the preceding year, bypass the breaker or otherwise take it out of the circuit for testing.
16) Inspect contact areas on the main plug-in assembly for signs of overheating or arcing.
17) Read and record compressor operating hours as shown on the indicator. SF_6 gas used in circuit breakers is subject to contamination as a result of the products released during the interruption of current. This contamination increases with the severity of the fault and with the deterioration

of the breaker contacts. Specific tests are not normally performed since the gas should be reconditioned on a regular basis in accordance with the manufacturer's recommendation.

18) Refer to any additional maintenance instructions or manufacturer recommendations attached to work orders.

4.4.2.5 AIR CIRCUIT BREAKERS

1) Inspect contacts for visual signs of overheating. Check contact clearance, contact wipe, toggles, latches, position indicator, auxiliary contacts, etc.
2) Inspect hardware and check wire connections for secureness.
3) Inspect arc interruption chambers.
4) Inspect relay contacts.
5) Check fuse clips for secureness.
6) Check the condition of bushings, porcelains, and contact surfaces.
7) Check the load conductor terminations.
8) Check the current transformer connections.
9) Check the grounding connections.
10) Check the lifting or racking mechanism (if applicable).
11) Check for loose, contaminated, or damaged bushings; loose terminals; and proper gas pressures.
12) Check the anti-condensation heaters. Read and record the number of operations indicated. If the breaker has not operated during the preceding year, bypass the breaker or otherwise take it out of the circuit for testing.
13) Inspect contact areas on the main plug-in assembly for signs of overheating or arcing.
14) Read and record compressor operating hours as shown on the indicator
15) Refer to any additional maintenance instructions or manufacturer recommendations attached to work orders.

4.4.2.6 VACUUM CIRCUIT BREAKERS

1) Check for loose, contaminated, or damaged bushings; loose terminals; oil leaks; and proper gas pressures.
2) Check the anti-condensation heaters.
3) Read and record the number of operations indicated. If the breaker has not operated during the preceding year, bypass the breaker or otherwise take it out of the circuit for testing.
4) Read and record compressor operating hours as shown on the indicator.
5) Refer to any additional maintenance instructions or manufacturer recommendations attached to work orders.

4.4.2.7 POWER TRANSFORMERS

1) Inspect the control cabinet, control relays, contactors, indicators, and the operating mechanism.
2) Look for loose, contaminated, or damaged bushings; loose terminals; and oil leaks.

3) Check oil levels in main tanks, tap changer compartment, and bushings.
4) Inspect the inert gas system (when applicable) for leakage, proper pressure, etc.
5) Read and record the operations counter indicator reading associated with the load tap changer, where applicable.
6) Observe oil temperature. Oil temperature should not exceed the sum of the maximum winding temperature as stated on the nameplate plus the ambient temperature (not to exceed 40C) plus 10C. Generally, oil temperature does not exceed 95 and 105C for 55 and 65C winding temperature rise units, respectively; since the ambient temperature rarely exceeds 30C for periods long enough to cause an oil temperature rise above these points.
7) Perform the power factor test
8) Perform the turns ratio test
9) Perform the winding resistance test
10) Perform the excitation current test
11) Perform the insulation resistance test
12) Refer to any additional maintenance instructions or manufacturer recommendations attached to work orders.

4.4.2.8 POTENTIAL AND CURRENT TRANSFORMERS, STATION SERVICE TRANSFORMERS

These assets contain no moving parts and are generally maintained using the predictive maintenance techniques (e.g. visual inspections, thermographic scans, and other checks) described in Section 4.4.1.8.

Due to the low risk of failure and the impact of substation outages required to isolate this equipment (or the operational requirements to switch load to avoid outages), cyclical preventative maintenance is not typically carried out on these assets. However, where station outages are planned for other maintenance requirements, additional testing or minor repairs may be carried out on this equipment, especially if prior issues were noted during visual inspections. Outages may also be warranted to conduct repairs (typically repairing loose connections) if hot spots are noted during thermographic scans.

4.5 REVENUE METERING AND INSTRUMENT TRANSFORMER MAINTENANCE

This type of Managed Assets requires additional Certification Maintenance in addition to the typical ‘physical’ maintenance (predictive, corrective, and preventative) required by most other types of Managed Assets.

Typically, each class of revenue meter and instrument transformer (current transformers and potential / voltage transformers) must be re-certified by an accredited testing organization on a recurring basis.

The frequency and nature of these recertification are dictated by regulations enforced by Measurement Canada (Industry Canada), a Federal regulator. Any other corrective maintenance is carried out on a case-by-case basis only if deficiencies are noted during visual inspections or thermographic scans.

5 SUMMARY OF ASSET CONDITION

In 2020, CNPI retained METSCO Energy Solutions Inc. to conduct a detailed Asset Condition Assessment (ACA), to review and assess CNPI's asset records, inspection and maintenance data, and overall asset condition for the purpose of informing its 2022-2026 DSP. The following sections provide a high-level summary of the ACA inputs, methodology and results. METSCO's ACA report is included as an appendix to the DSP, and provides detailed information on the available data, condition assessment methodology and overall condition assessment results for each asset category.

5.1 DISTRIBUTION SUBSTATIONS

Due to the relatively low quantity, high value, and consequence of failure, regular and thorough inspection and maintenance activities are undertaken substation assets, as described in Section 4.4 of this document. METSCO was provided with lists of substation equipment, along with copies of inspection forms and test results spanning multiple years for all substations/equipment.

After reviewing all substation data and following up with CNPI on any inconsistencies, exceptions, or questions of interpretation, METSCO developed condition parameters and weighting factors used to assess the overall condition for various types of substation assets. A health index score was calculated then calculated for each individual asset, the results of which are summarized in Figure 4:

Figure 4: Station Asset Health Index (HI) Results

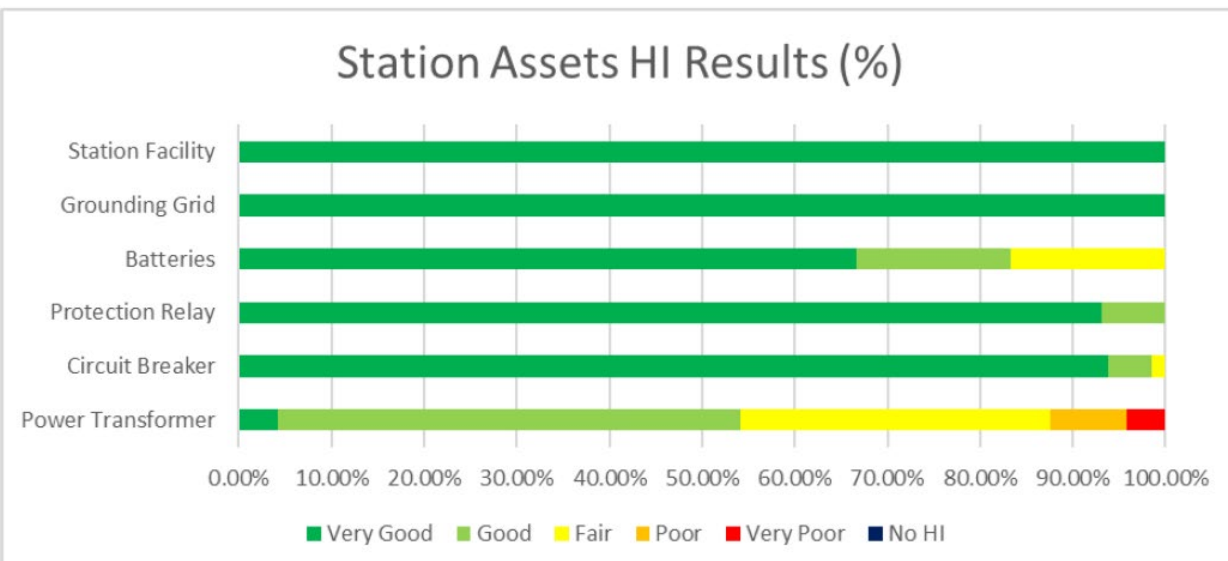


Table 9 provides a list of specific substation assets that where the ACA identified an overall condition of Fair, Poor, or Very Poor.

Table 9: Substation Assets with Fair, Poor or Very Poor Condition

Asset Class	Station	Asset ID	HI Score
Power Transformer	Station 12	S12T1	Fair
	Station 12	S12T2	Fair
	Station 12	S12T3	Fair
	Station 12	S12TS	Fair
	Station 19	S19T1	Fair
	Station 19	S19T2	Fair
	Killaly	KST1	Poor
	Killaly	KST2	Poor
	Herbert	HST1	Fair
	Gananoque Down Town	GDT1	Fair
	Gananoque Down Town	GDT2	Very Poor
Circuit Breakers	Station 17	R400	Fair
Batteries	Station 12	STATION_12-BTRY	Fair
	Gananoque Down Town	GANANOQUE_DOWN_TOWN-BTRY	Fair

5.2 DISTRIBUTION LINE ASSETS

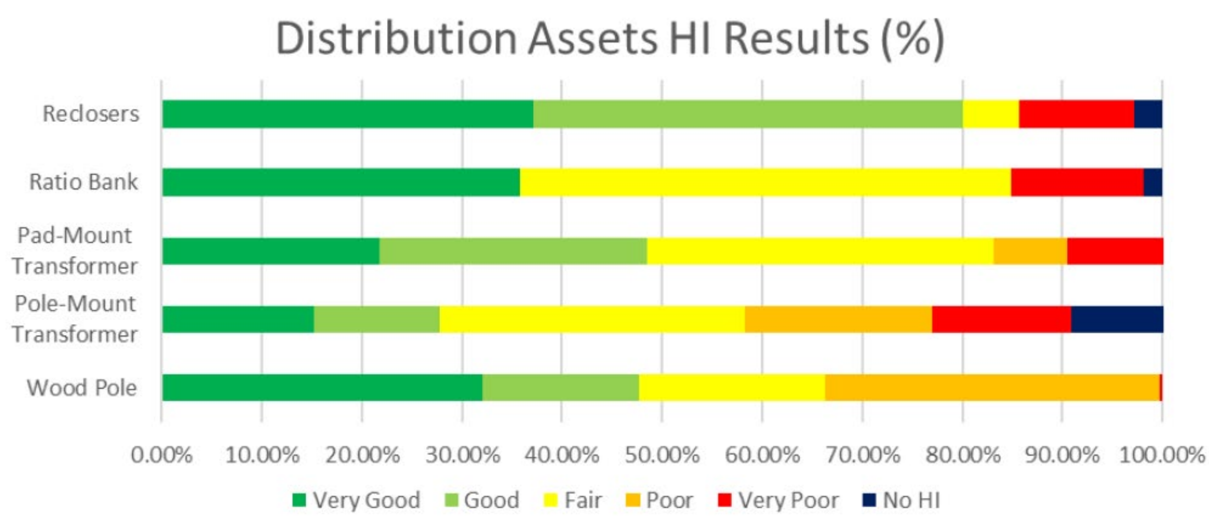
Compared with substation assets, distribution line assets are generally deployed in significantly higher quantities and have a wide range of costs. The consequence of failure and the restoration time and costs following a failure also vary significantly based on asset type, location and mode of failure. As discussed in Section 4.2 of this document, detailed inspection and testing programs are applied to wood poles, but most other line assets are subject to periodic visual inspections and thermographic scans. CNPI provided METSCO with lists of its distribution line assets, along with any available information on asset age, nameplate data, physical characteristics, along with pole testing results where available, and copies of feeder inspection documents.

As a result of CNPI's deficiency-based inspection programs for most distribution line assets, asset age was the only condition parameter available for assets other than wood poles.

For wood poles, detailed testing results for a subset of CNPI's poles were available, allowing for the use of eight condition parameters in calculating the Health Index. The health index results for poles without test results were extrapolated based on the health index distribution for poles in the same age group that were tested.

Figure 5 summarizes the condition of CNPI's substation assets:

Figure 5: Distribution Line Asset Health Index (HI) Results



6 OVERVIEW OF DISTRIBUTION SYSTEM PLANNING

At CNPI, distribution system planning is a continuous and evolving process designed to meet the present and changing needs of a variety of stakeholders. Prior versions of CNPI's AMP included detailed descriptions of CNPI's asset management processes in the context of overall system planning, and development of capital and O&M plans and budgets.

As CNPI's DSP has continued to evolve, these process details and flow charts have been moved to the DSP, where the AMP is considered as one of many inputs in CNPI's overall system planning process. The remainder of this section summarizes how the AMP interacts with CNPI's other system planning processes over various planning horizons.

6.1 LONG-TERM PLANNING

Long range planning at CNPI is generally performed through the preparation and periodic review of Area Planning Studies (APS), which include load growth projections. The APS also includes consideration of changes in technology, government policy, standards, guidelines, or codes that could impact future electrical load.

The APS analyzes the existing distribution system, with various combinations of net system load and contingency scenarios over a planning horizon of ten years. Technical issues like component capacities, ability to operate within voltage requirements, and system losses are reviewed, and system deficiencies (present and predicted through the load forecast period) are identified.

Various alternatives and solutions are proposed, and then analyzed to ensure that they adequately address system deficiencies. Recommendations are made in consideration of cost/benefit analysis, where the cost of capital investments, operating costs and system losses are compared on a net present value basis.

The APS does not attempt to identify or address all asset condition issues, as these concerns are often more immediate in nature and are resolved through a 5-year (medium term) budget planning process. However, if any distribution assets are known to be approaching the end of their useful lives, this information is considered when proposing alternative solutions. Specifically, where the AMP identifies that certain critical assets are approaching end-of-life, the APS will place additional emphasis on evaluating contingencies involving those assets, and evaluating the performance of alternatives for like-for-like replacement compared to other options, in order to inform the efficient planning and design of replacement assets.

Similarly, where the APS identifies system performance issues, consideration is given to whether any of the major assets involved are approaching end-of-life. In these cases, changes to asset specifications during end-of-life replacements (e.g. larger conductor size, larger transformer rating, etc.) may improve system performance without investments in new equipment.

6.2 MEDIUM-TERM PLANNING (5-YEAR PLANNING HORIZON)

CNPI uses results from its long-term planning efforts (specifically the APS) and other reports, such as asset condition reports and reliability studies, to perform 'tactical' planning which covers a five-year period. Results of customer and municipal engagement activities and any changes to the regulatory environment are also considered in medium-term planning. Typical inputs to medium-term planning include:

1) Customer-driven needs
2) Municipal-driven needs
3) Health, Safety and Environmental issues
4) Regulatory requirements
5) Reliability analysis
6) Asset replacement requirements (based on the processes described in this AMP)
7) Requirements for system expansions, upgrades or reinforcements (as identified through long-term planning and/or the Regional Planning Process)
8) Initiatives related to grid modernization, distributed energy resources and changes in energy usage (based on regulatory requirements, results of engagement activities, and any project-specific requests or applications)

The medium-term planning process identifies and prioritize projects for inclusion in the 5-year capital plan. It also considers the effectiveness of maintenance programs identified in this AMP, and whether any adjustments to those programs, or any one-time major maintenance activities are required.

6.3 SHORT-TERM PLANNING (1-YEAR PLANNING HORIZON)

Short- term planning involves developing specific plans to implement the specific projects identified in the current year budget, as well as to operate and maintain the distribution system(s) in a safe and reliable manner.

It also addresses short-term needs, such as connection of customers that were not identified previously during medium term planning. Typical inputs to the short-term plan include

1) Specific capital or maintenance requirements to address high-priority deficiencies identified during previous inspection and maintenance programs
2) Current Budget Year Project Design
3) Customer-Driven Asset Development
4) Municipal and Developer-Driven Asset Development
5) Other Short-term Projects

APPENDICES

CANADIAN NIAGARA POWER INC.
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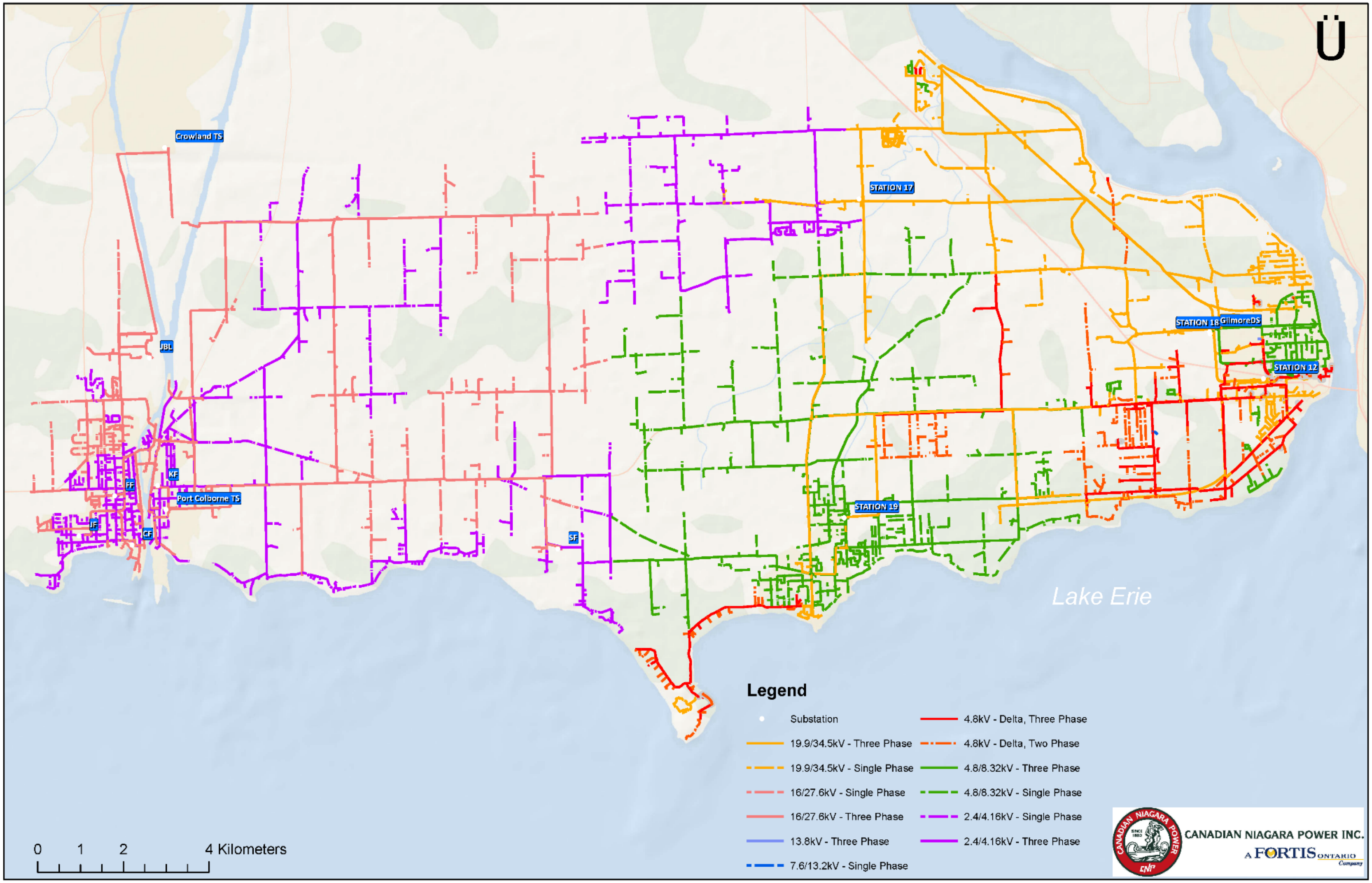
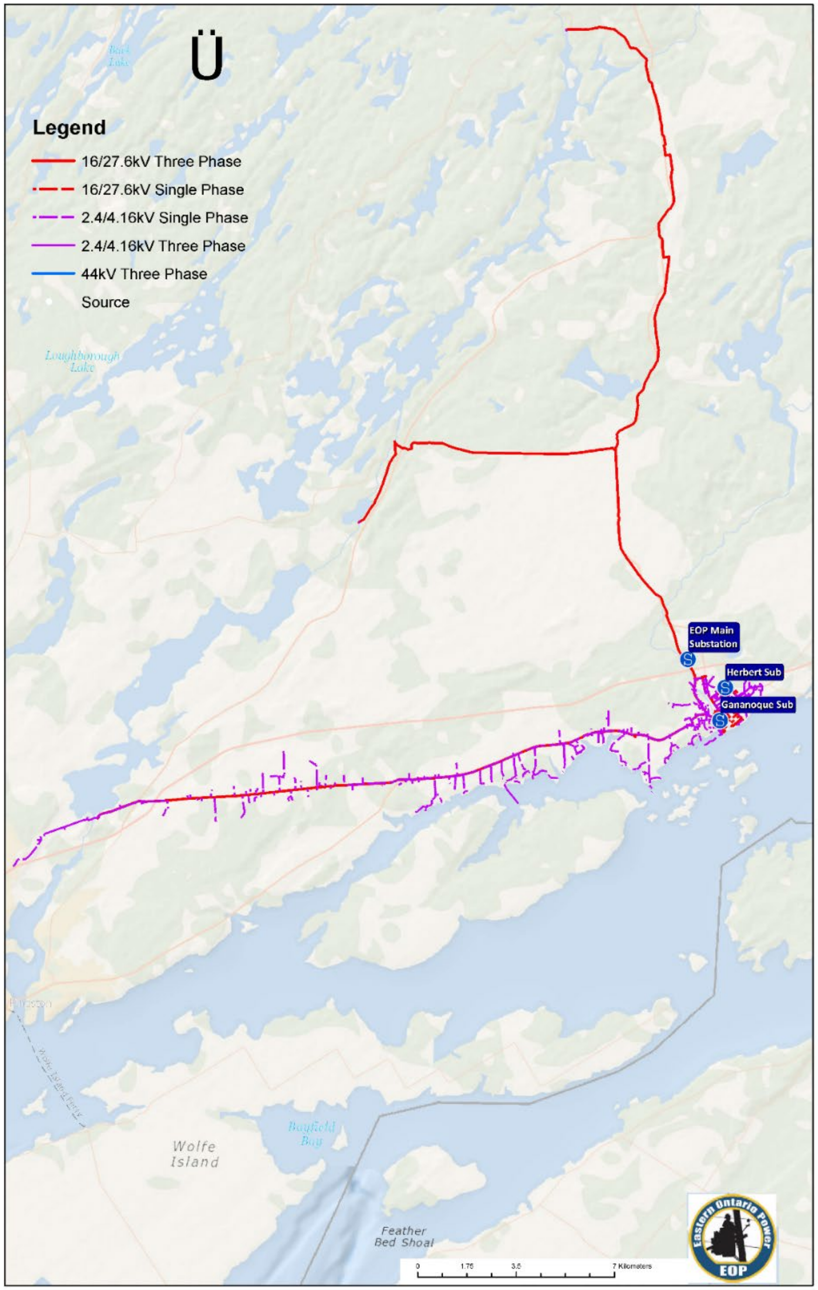
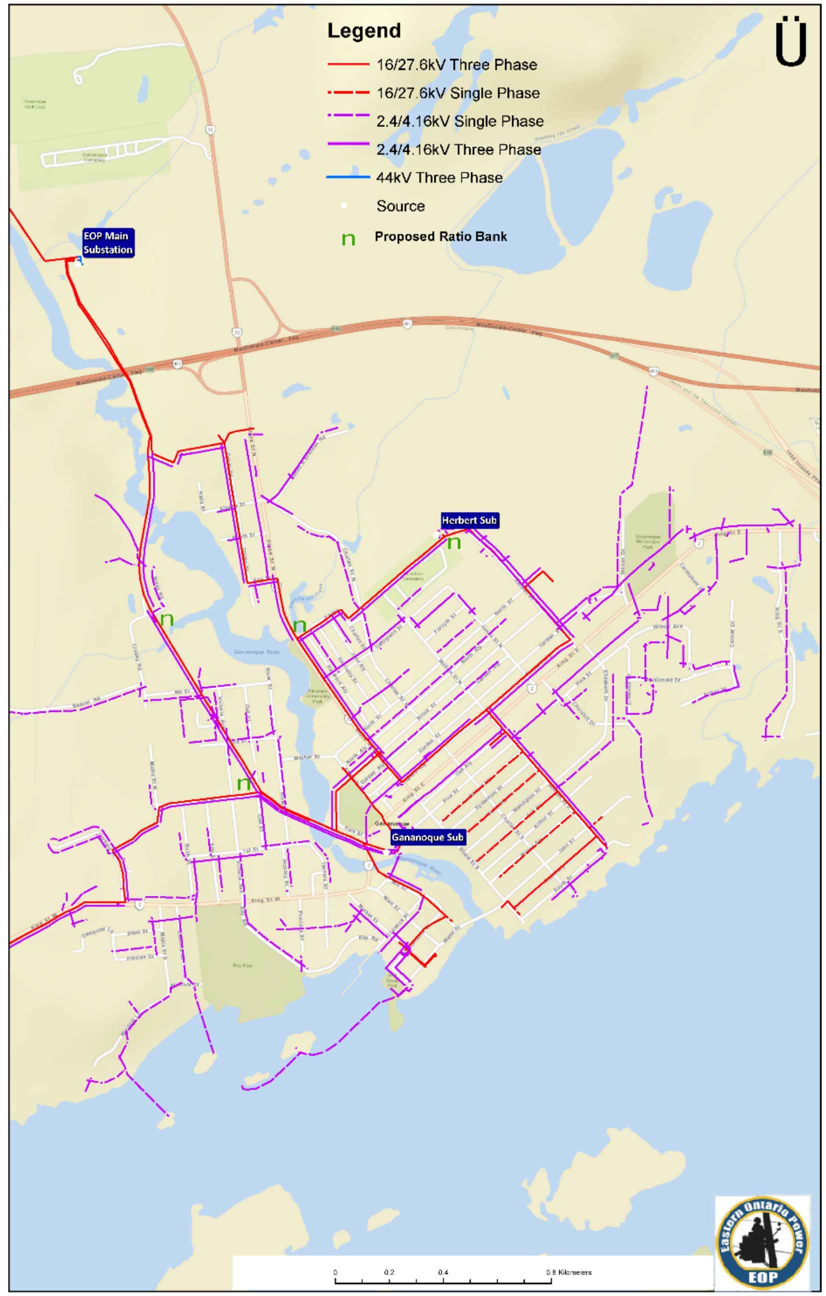
AMP APPENDIX A:
MAPS OF CNPI SERVICE AREAS

A1 – Fort Erie and Port Colborne Distribution Systems (CNP)



A2 – Gananoque Distribution System (EOP): Overview (Left); Town of Gananoque Focus (Right)





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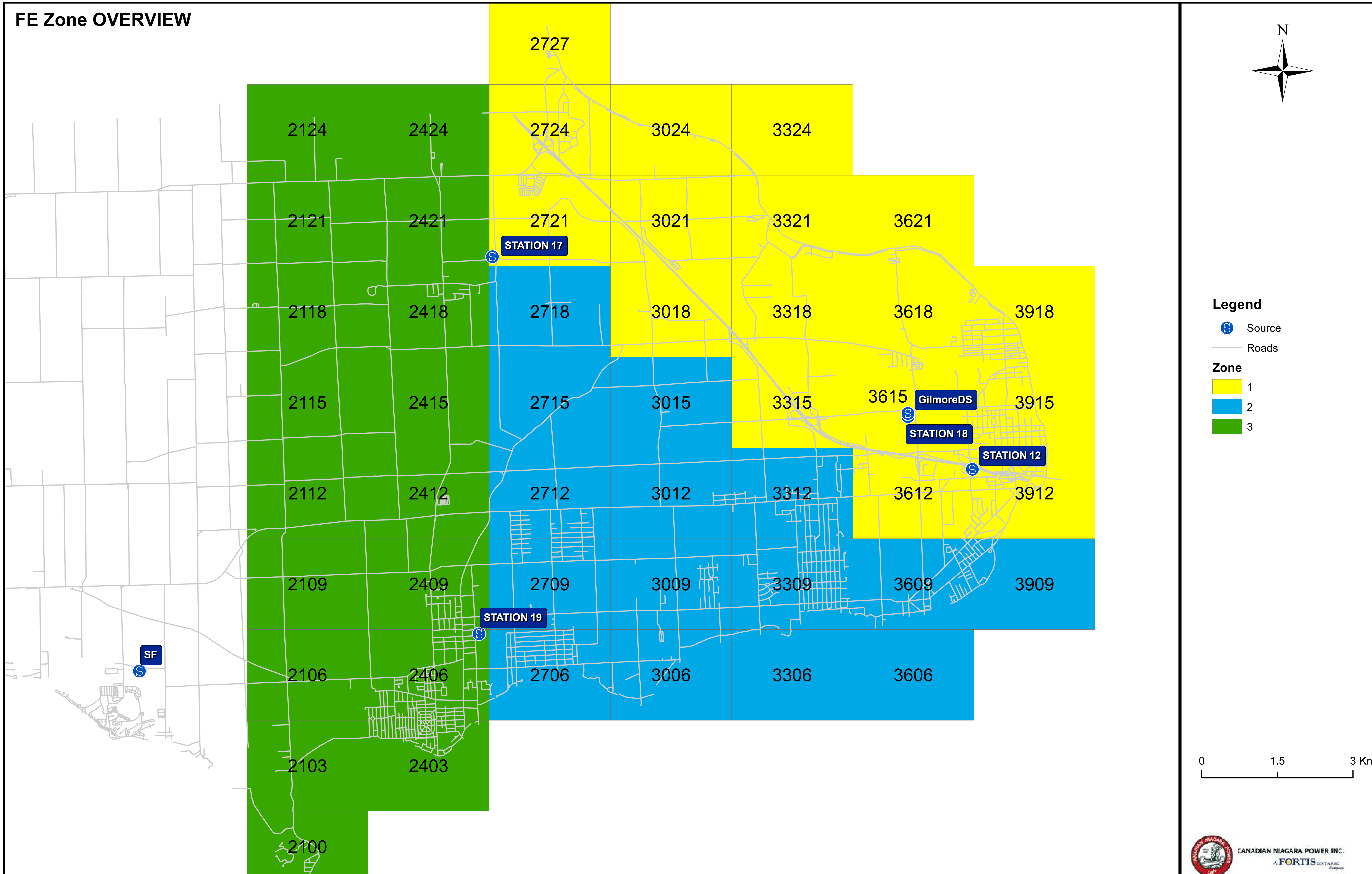
AMP APPENDIX B:
CNPI ZONE MAPS


FE Zone OVERVIEW
2727
2124
2424
2724
3024
3324
2121
2421
2721
3021
3321
3621
STATION 17
2118
2418
2718
3018
3318
3618
3918
2115
2415
2715
3015
3315
3615
GilmoreDS
3915
STATION 18
STATION 12
2112
2412
2712
3012
3312
3612
3912
2109
2409
2709
3009
3309
3609
3909
STATION 19
SF
2106
2406
2706
3006
3306
3606
2103
2403
2100
N
Legend
Source
Roads
Zone
1
2
3
0
1.5
3 Km
CANADIAN NIAGARA POWER INC.
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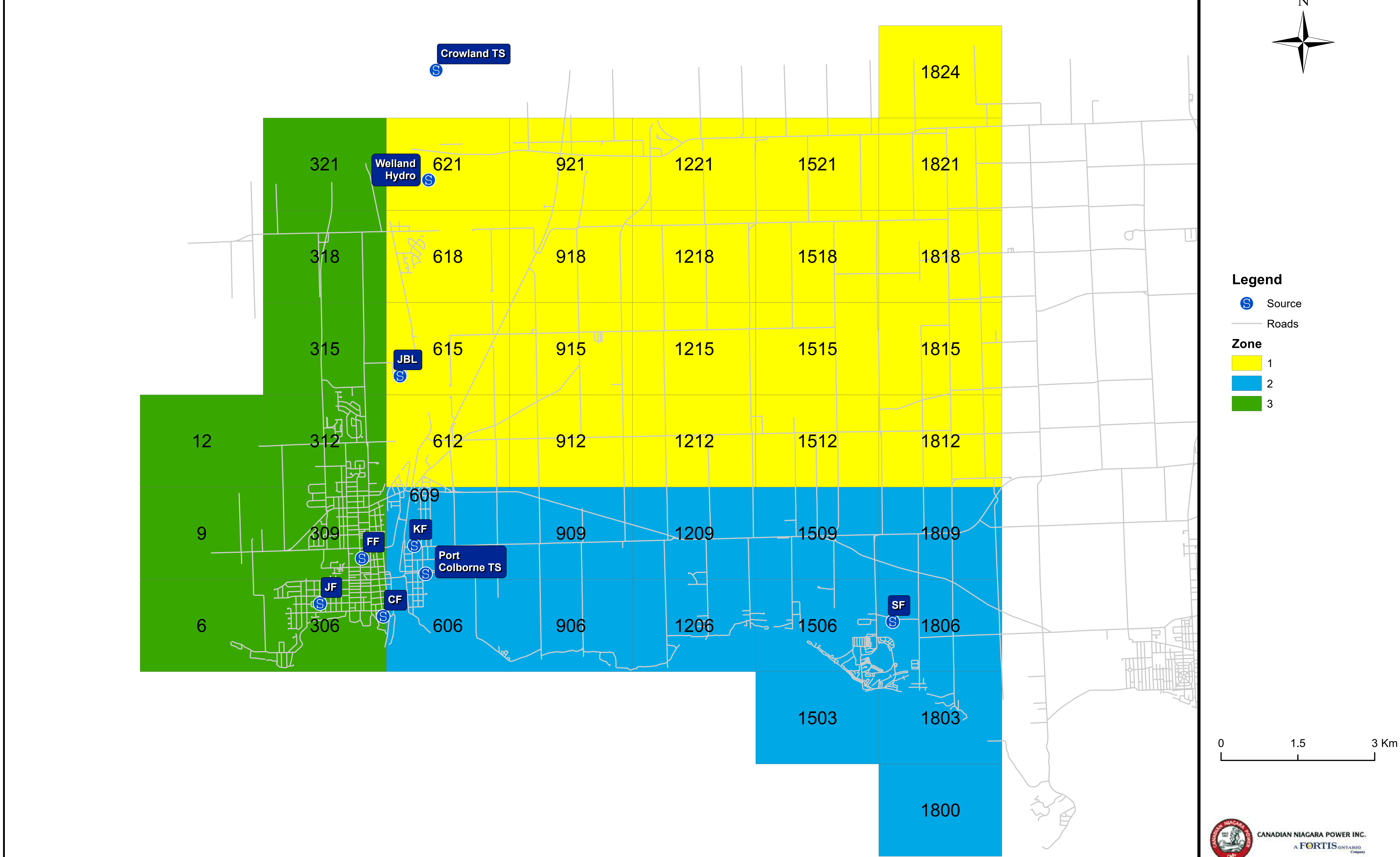
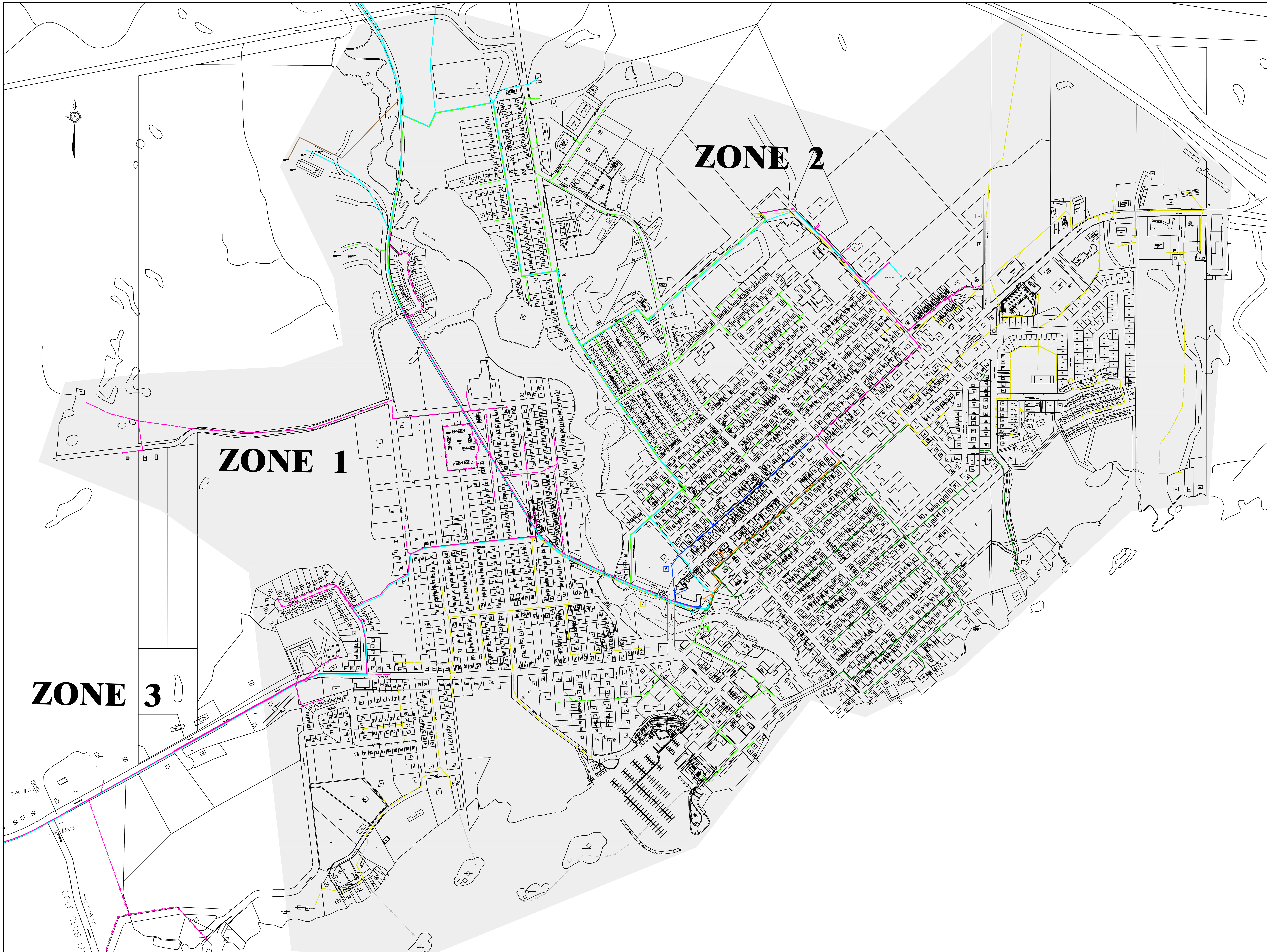
PC Zone OVERVIEW





Revision				
NO.	DATE	DESCRIPTION	BY	CHK
1				

Notes:

LEGEND

SWITCHES
N.O. AERIAL LB SW
N.C. AERIAL LB SW
N.O. SWITCH
N.C. SWITCH
1234 SWITCH NUMBER AMPACITY, RATING 100A 40K

PADMOUNTED
SINGLE SWITCH
2-WAY SWITCH
3-WAY SWITCH
4-WAY SWITCH

UNDERGROUND
2-WAY SWITCH
3-WAY SWITCH
4-WAY SWITCH
FEED-THROUGH

TRANSFORMERS

PADMOUNTS
1ø PADMOUNT FEED THROUGH
1ø PADMOUNT FEED THROUGH W/ F.T. BUSHING
3ø PADMOUNT FEED THROUGH
3ø PADMOUNT DIRECT FEED
3ø PADMOUNT LIVE FRONT

TRANSCLOSURES
1ø FEED THROUGH
3ø FEED THROUGH
3ø DIRECT FEED
1ø PADMOUNT LIVE FRONT

IN VAULTS
1 PHASE
3 PHASE

POLE MOUNTED
POLE-TOP
3ø POLETOP
POLE-TRANS

STATION TYPE
3 PHASE
3 PHASE STEP DOWN

MISCELLANEOUS DEVICES
LINE CAPACITOR
LINE VOLTAGE REGULATOR
STATION
CUSTOMER STATION
CIRCUIT BREAKER
PRIMARY METER
SPLICE
MSO (JUMPER)
OH TO URG TRANSITION
RECLOSER
F1263 FEEDER NUMBER
CHANGE IN WIRE
CONNECTED
NOT CONNECTED

LINETYPES
1ø OH PRIMARY
2ø OH PRIMARY
3ø OH PRIMARY
1ø DIRECT BURIED PRIMARY
2ø DIRECT BURIED PRIMARY
3ø DIRECT BURIED PRIMARY
1ø PRIMARY IN CONDUIT
2ø PRIMARY IN CONDUIT
3ø PRIMARY IN CONDUIT
26.4kV
8.3kV
7.6kV
4.8kV
4.16kV

TREE TRIMMING COMPLETED
D / M / Y

TREE TRIMMING BY:

INSPECTION COMPLETED
D / M / Y

INSPECTION BY:

Eastern Ontario Power
A FORTIS ONTARIO Company

TOWN OF GANANOQUE & RURAL
ZONE AREA
TREE TRIMMING

DR. M.E.L.	CH. M.P.	APP'D	SCALE N.T.S.
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GA – 30040		REV. 1	SIZE D
E-FILE EOP/DWGS			

CANADIAN NIAGARA POWER INC.
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DSP APPENDIX B:
HYDRO ONE REGIONAL PLANNING STATUS UPDATE

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

May 5, 2021

Ajar Garg
Hydro One Networks Inc.
Via Email: agay.garg@HydroOne.com

Re: Request for Regional Planning Status Letter

Canadian Niagara Power Inc. ("CNPI") intends to file a Cost of Service application with the Ontario Energy Board ("OEB") by May 31, 2021. The application will be based on a 2022 test year, with CNPI's Distribution System Plan ("DSP") covering the five-year period from 2022-2026. In addition to its Niagara service area, CNPI operates as Eastern Ontario Power ("EOP") in the Town of Gananoque and surrounding area.

The first Needs Assessment for the Niagara Region recommended that thermal overloading of a specific 115 kV circuit be addressed as part of a Local Plan, and concluded that no further regional coordination was required for the 2015-2024 period. CNPI has since worked closely with Hydro One in relation to equipment replacements at Port Colborne TS and has also participated in the initial steps of the second round of regional planning for this area in 2021.

The most recent Needs Assessment report for the Peterborough to Kingston Region (February 2020) identified overloading concerns for the Frontenac TS, which supplies EOP as an embedded distributor to HONI. The study team recommended initiating an Integrated Regional Resource Plan and/or a Regional Infrastructure Plan to address this need, among others, in the longer term. EOP anticipates participating in the IRRP and/or RIP processes as required. EOP has also worked closely with HONI to coordinate 44 kV line upgrades to improve reliability and contingency options for its service area.

CNPI is requesting a regional planning status letter from Hydro One, summarizing the current status of regional planning efforts for the Niagara and Peterborough to Kingston Regions. Based on CNPI's understanding of current status as summarized above, we have not included any specific projects in our DSP to address regional needs, but we intend to maintain flexibility to incorporate any requirements that may be identified during the second round of regional planning.

Regards,

Greg Beharriell, P. Eng.
Manager, Regulatory Affairs
greg.beharriell@cnpower.com

DSP APPENDIX C:
CNPI OEB SCORECARD AND MD&A

Scorecard - Canadian Niagara Power Inc.

10/21/2020

Performance Outcomes	Performance Categories	Measures		2015	2016	2017	2018	2019	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		94.40%	91.10%	90.81%	90.40%	93.27%		90.00%	
		Scheduled Appointments Met On Time		100.00%	100.00%	100.00%	100.00%	100.00%		90.00%	
		Telephone Calls Answered On Time		76.10%	75.70%	77.33%	80.98%	79.73%		65.00%	
	Customer Satisfaction	First Contact Resolution		99.80%	99.20%	99.80%	99.84%	99.94%			
		Billing Accuracy		99.91%	99.81%	99.91%	99.90%	99.92%		98.00%	
		Customer Satisfaction Survey Results		94%	85%	91%	91%	91%			
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		81.00%	81.00%	81.00%	81.00%	83.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		NI	C	C	C	C			C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	1			0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.963			0.137
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		2.36	3.47	3.11	2.45	3.01			2.26
		Average Number of Times that Power to a Customer is Interrupted [2]		2.78	2.29	2.04	2.14	2.00			2.21
	Asset Management	Distribution System Plan Implementation Progress		Completed	Complete	In Progress	Completed	Completed			
	Cost Control	Efficiency Assessment		4	4	4	4	4			
		Total Cost per Customer [3]		$778	$796	$773	$867	$893			
		Total Cost per Km of Line [3]		$21,726	$22,371	$21,875	$24,425	$16,421			
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]		12.30%	51.39%	84.23%	101.00%	120.00%			28.48 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time				100.00%					
		New Micro-embedded Generation Facilities Connected On Time		100.00%	100.00%	100.00%	100.00%			90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	**Financial Ratios**	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.35	0.33	0.36	0.44	0.28			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.72	1.64	2.11	3.03	2.92			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	8.93%	8.93%	8.78%	8.78%	8.78%			
			Achieved	10.00%	8.97%	10.70%	6.58%	5.84%			

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 now discontinued 2015-2020 Conservation First Framework. 2019 results include savings reported to the IESO up until the end of February 2020.

Legend:

5-year trend: up, down, flat

Current year: target met, target not met

2019 Scorecard Management Discussion and Analysis (“2019 Scorecard MD&A”)

The link below provides a document titled “Scorecard - Performance Measure Descriptions” that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard’s measures in the 2019 Scorecard MD&A:
http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf

Scorecard MD&A - General Overview

In 2019, CNPI continued to meet or exceed the majority of its performance targets.

In 2020, CNPI expects to continue to improve its overall scorecard performance results as compared to previous years. These performance improvements are expected as a result of enhanced system reliability due to CNPI’s investment in its distribution system and continued responsiveness to customer feedback.

Service Quality

- **New Residential/Small Business Services Connected on Time**

In 2019, CNPI connected 93.2% of the 297 new eligible low-voltage residential and small business customers within the Ontario Energy Board’s prescribed five-day timeline. Since 2011, CNPI has consistently exceeded the Ontario Energy Board’s performance standard.

- **Scheduled Appointments Met On Time**

CNPI continues to exceed the Ontario Energy Board standard of meeting customers as requested within the prescribed timelines set out by the Ontario Energy Board.

- **Telephone Calls Answered On Time**

In 2019, customer service representatives answered 79.7% of CNPI’s 33,897 calls within 30 seconds. This exceeds the Ontario Energy Board’s mandated 65% target. CNPI continues to offer and promote self-serve options and utilizes social media to engage and inform customers in an effort to offer customers additional channels to interact with the Company.

Customer Satisfaction

- **First Contact Resolution**

CNPI measured First Contact Resolution by tracking the number of escalated calls as a percentage of total calls taken by the customer contact center. In 2019, only 0.06% of calls were escalated.

- **Billing Accuracy**

For 2019, CNPI issued approximately 357,358 invoices and 99.92% were accurate. This is above the industry standard of 98%.

- **Customer Satisfaction Survey Results**

CNPI conducts its customer satisfaction surveys through a third-party survey provider, UtilityPULSE, consistent with many other LDCs in the province. Phone numbers were randomly selected so that 85 per cent of the interviews were conducted with residential customers and 15 per cent with general service customers. The 2019 satisfaction score of 91% is the near the Ontario benchmark of 92%.

The survey provides useful information to better meet the needs of CNPI's customers and is incorporated into CNPI's distribution system plan, capital planning and overall company objectives.

Safety

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

In 2019, UtilityPulse was also engaged to complete surveys in relation to "Public Awareness of Electrical Safety". On completion of this survey, UtilityPulse generated a "Public Safety Awareness Index Score" for CNPI and other LDC's. Province-wide scores ranged from 80% to 85%, with both average and median Index Scores of 83%. CNPI's score of 83% suggests that members of the public are generally well-informed about the safety hazards associated with electrical distribution systems, but also that further education and engagement would be beneficial. This survey on "Public Awareness of Electrical Safety" is completed on a two-year cycle and will be completed again by CNPI in 2021.

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

This component includes the results of an Annual Audit, Declaration of Compliance, Due Diligence Inspections, Public Safety Concerns and Compliance Investigations. All the elements are evaluated as a whole and determine the status of compliance (Non-Compliant, Needs Improvement, or Compliant). Based on results provided by ESA, CNPI's status is Compliant.

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

"Serious electrical incidents", as defined by Regulation 22/04, make up Component C. The metric details the number of and rate of "serious electrical incidents" occurring on a distributor's assets and is normalized per 10, 100 or 1,000 km of line (10km for total lines under 100km, 1000km for total lines over 1000km, and 100km for all the others).

Based on results provided by ESA, CNPI had one incident in 2019. This incident involved a mast of a sailboat coming into contact with a power line while being removed from a boat launch. There was damage caused to the mast of the sailboat, but no further injuries with this incident. The power line was permanently raised and additional safety protocols added to avoid another occurrence at the marina.

System Reliability

- **Average Number of Hours that Power to a Customer is Interrupted**

CNPI's customers experienced a slight increase in the average duration of electrical service disruptions in 2019 compared to 2018. A few factors continue to contribute to the increasing long-term trend, such as increased storm activity within the Niagara Region.

CNPI continues to invest in grid modernization in order to gain visibility on the state of the distribution system and improve overall response and restoration times. Grid modernization initiatives continue to include the deployment of automated devices fault indicating equipment and the ongoing enhancement of and implementation of its outage management system. CNPI understands that reliability of electrical service is a high priority for its customers and continues to invest in replacement of end-of-life assets as well as a defined inspection and maintenance program including vegetation management.

- **Average Number of Times that Power to a Customer is Interrupted**

CNPI’s customers experienced a slight decrease in the average number of electrical service disruptions in 2019 compared to 2018. The 2019 result represents the lowest outage frequency in the 2015-2019 period, and marks the third straight year where outage frequency is better than the OEB target.

CNPI has deployed several initiatives aimed at reducing the number of electrical service interruptions such as the vegetation management program and cyclical asset preventative maintenance programs.

CNPI reviews outage statistics on a monthly basis to identify areas of poor distribution system performance. This process indicates any trends in poor performance and identifies opportunities to improve reliability. CNPI also completes asset condition assessments to identify assets that present a risk of impacting system reliability. CNPI uses reliability indicators and asset condition assessment data as key drivers into the system planning process.

Asset Management

- **Distribution System Plan Implementation Progress**

CNPI completed the majority of planned 2019 capital projects in accordance with its Distribution System Plan, with emphasis on continuing voltage conversion and substation rebuild work to improve the safety and reliability of its distribution system. CNPI has also continued to invest in system expansions to accommodate requests for new services, due to new subdivision development above historical levels. All maintenance activity as defined in the Distribution Asset Management Plan was completed in 2019.

Cost Control

- **Efficiency Assessment**

The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC on behalf of the Ontario Energy Board to produce a single efficiency ranking. The electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual and predicted costs. The statistical model developed by Pacific Economics Group to predict a distributor's costs relies on a data set that includes all distributors in Ontario.

For 2019, CNPI was placed in Group 4 indicating that actual costs are within 25% of the costs predicted by the statistical model. CNPI's total costs are reflective of its continued re-investment in its distribution system, as well as the costs of providing IT services to a number of other LDC's. While the PEG model captures the cost of the assets required to provide IT services to other LDC's, it does not account for the related revenue collected by CNPI. If CNPI's actual costs were adjusted to consider these revenue offsets, it would be placed in Group 3, indicating that actual costs are within +/- 10% of those predicted by the model.

- **Total Cost per Customer**

The statistical model developed by Pacific Economics Group produces total capital and operating costs for each distributor that can be used for the purpose of comparing distributors. This amount is then divided by the total number of customers that CNPI serves to determine Total Cost per Customer. The cost performance result for 2019 is $893 per customer, which is a 3% increase over 2018.

Over the 2015 to 2019 period covered by the scorecard, CNPI faced both inflationary cost increases, as well as cost increases associated with investments in programs for asset replacement, system improvement, and vegetation management that are sustainable in the long term. In contrast, CNPI's customer count increased by only 2.6% over the entire five year period, with a result that cost increases are not offset by customer growth.

- **Total Cost per Km of Line**

This measure uses the same total cost that is used in the Cost per Customer calculation above. The total cost is divided by the total kilometers of line that CNPI operates to serve its customers. CNPI's 2019 result is $16,421 per km of line, a 32% decrease over 2018. This decrease is due to changes in OEB reporting requirements used to calculate this parameter. In 2019, CNPI started reporting on the length of its low-voltage secondary lines, in addition to the length or higher-voltage primary lines reported in prior years. This increased the total line length used in the calculation from 1,038 km in 2018, to 1,602 km in 2019.

Conservation & Demand Management

- **Net Cumulative Energy Savings**

As per the Ministerial Directives dated March 21st, 2019, “Discontinuation of the Conservation First Framework” and “Interim Framework for the delivery of Energy Efficiency Programs”, the IESO centrally delivers energy-efficiency programs as of April 1st, 2019. As part of these directives, LDCs are not to receive any status updates or reporting on their progress towards their Conservation First Framework savings targets – including the Final Verified Results Report that had been previously used for this scorecard.

On the basis of the OEB-provided CDM progress figures, CNPI achieved 120.00% of its Net Energy Savings target for the 2015 – 2020 timeframe. CNPI fully leveraged the suite of Independent Electricity System Operator (“IESO”) province-wide demand management programs and placed emphasis on supporting the conservation efforts of large commercial, industrial and institutional customers. Much of this success can be attributed to strong participation by commercial customers in the Retrofit Program.

Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**

CNPI did not receive any requests for renewable generation connections requiring Connection Impact Assessments in 2019.

- **New Micro-embedded Generation Facilities Connected On Time**

In 2019, CNPI connected zero (0) new micro-embedded generation facilities (microFIT projects of less than 10 kW).

Financial Ratios

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

The Scorecard reports the current ratio for CNPI’s segmented distribution business as 0.28 for 2019 (2018 0.44). CNPI however manages liquidity on a consolidated basis that includes both its transmission and distribution divisions. On this basis, the 2019 liquidity current ratio based on CNPI’s audited financial statements, adjusted to exclude due to related parties, is 1.41 (2018 1.55), which has not significantly changed from prior year. Going forward, the liquidity ratio is expected to be maintained at a level greater than 1, indicating that CNPI can pay its short term debts and financial obligations.

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

The Ontario Energy Board uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5. The Scorecard reports the total debt to equity ratio for CNPI's segmented distribution business as 2.92 for 2019 (2018 3.03). CNPI however manages its capital structure on a consolidated basis that includes both its transmission and distribution divisions. On this basis, the 2019 leverage debt to equity ratio based on CNPI's audited financial statements, adjusted to include due to related parties, is 1.56 (2018 1.54), which has not significantly changed from prior year. Going forward, the leverage ratio is expected to be maintained at a level near the 1.5 deemed capital mix noted above.

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

CNPI's 2019 distribution rates were approved by the Ontario Energy Board as part of its 4th Generation Incentive Rate-Setting application. CNPI's last Cost of Service application was for rates effective January 1, 2017 and this included an expected (deemed) regulatory return on equity of 8.78%. The Ontario Energy Board allows a distributor to earn within +/- 3% of the expected return on equity.

- **Profitability: Regulatory Return on Equity – Achieved**

CNPI's return achieved in 2019 is 5.84% (2018 6.58%), which is within the +/- 3% range allowed by the Ontario Energy Board. CNPI achieved returns are lower in 2019 as compared to 2018 due to a $0.2 million (7.1%) decrease in adjusted regulated net income and a $4.5 million (4.7%) increase in rate base.

Note to Readers of 2019 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management's best judgement on the reporting date of the performance scorecard, and could be markedly different in the future.

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

DSP APPENDIX D: CNPI ASSET CONDITION ASSESSMENT ("ACA")

METSCO

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CANADIAN NIAGARA POWER INC.

ASSET CONDITION ASSESSMENT FINAL REPORT 2020

Prepared by

METSCO
MAKING IT POSSIBLE

METSCO Report no. P-20-142

October 2020

Disclaimer

This report was prepared by METSCO Energy Solutions Inc. (METSCO) for the sole benefit of Canadian Niagara Power Inc. (CNPI or "the utility"), in accordance with the terms of the METSCO proposal.

Some of the information and statements contained in the Asset Condition Assessment (ACA) are comprised of, or are based on, assumptions, estimates, forecasts and predictions and projections made by METSCO and CNPI. In addition, some of the information and statements in the ACA are based on actions that CNPI currently intends to take in the future. As circumstances change, assumptions and estimates may prove to be obsolete, events may not occur as forecasted or projected, and CNPI may at a later date decide to take different actions to those it currently intends to take.

Except for any statutory liability which cannot be excluded, METSCO and CNPI will not be liable, whether in contract, tort (including negligence), equity or otherwise, to compensate or indemnify any person for any loss, injury or damage arising directly or indirectly from any person using, or relying on any content of this ACA Report.

Asset Condition Assessment Report 2020
Final Report

October 2020

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Executive Summary

Context of the Study

Canadian Niagara Power Inc. (CNPI) is an electricity distributor operating a system comprised of 14 substations and over 1,100 km of medium-voltage distribution lines delivering electricity to over 29,000 residential and commercial customers in the Fort Erie, Port Colborne, and Gananoque areas. The service areas are often communicated by CNPI as either 'Niagara' (Fort Erie and Port Colborne) or 'Eastern Ontario Power' (EOP), (CNPI operates as EOP in the Gananoque area). CNPI engaged METSCO Energy Solutions Inc. (METSCO) to prepare a comprehensive Asset Condition Assessment (ACA) study for the assets comprising CNPI's distribution system. The ACA is required as one of the key inputs for the preparation of CNPI's five-year Distribution System Plan (DSP), developed in accordance with the filing requirements for electricity distributors enacted by the Ontario Energy Board (OEB).

Scope of the Study

METSCO's work included interviews with CNPI subject matter experts to define the Health Indices appropriate for the asset types, review, consolidation, and analysis of CNPI's asset records, calculation of the Health Index (HI) values, and preparation of the final document. METSCO assessed asset health for the following asset classes:

- Distribution Wood Poles
- Distribution Transformers
- Distribution Ratio Banks
- Station Power Transformers
- Station Circuit Breakers
- Station Reclosers
- Station Protection Relays
- Station Battery Banks
- Station Grounding Grids
- Station Facilities

All asset condition data used in the study is maintained by CNPI as part of its regular asset management practices and collected in the course of inspection and testing activities that to METSCO's knowledge, are compliant with the Distribution System Code (DSC) requirements. METSCO received CNPI's data between May 2020 and August 2020.

Methodology and Findings

For all asset classes that underwent assessment, METSCO used a consistent scale of asset health from Very Good to Very Poor. The numerical HI corresponding to each condition category serves as an indicator of an asset's remaining life, expressed as a percentage. Table 0-1 presents the HI ranges corresponding to each condition score, along with their corresponding implications as to the follow-up actions required by the asset manager at CNPI.

Table 0-1: Health Index Ranges and Corresponding Implications for the Asset Condition

Health Index Score (%)	Condition	Description	Implications
[85-100]	Very Good	Some evidence of aging or minor deterioration of a limited number of components	Normal Maintenance
[70-85)	Good	Significant Deterioration of some components	Normal Maintenance
[50-70)	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on the unit's criticality
[30-50)	Poor	Widespread serious deterioration	Start the planning process to replace or rehabilitate, considering the risk and consequences of failure
[0-30)	Very Poor	Extensive serious deterioration	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment

Using this scale, METSCO calculated health information scores for every asset in the scope of the assessment using a standard methodology, adapted to this engagement based on data availability and other relevant considerations. The assessment of health of each asset class is made up of available and relevant “condition parameters” – individual characteristics of the state of degradation of an asset’s components – each with its own sub-scale of assessment, and a weighting contribution that represents the percentage in the overall score.

The results of our assessment are presented as either Health Indices, or “One- or Two-Parameter Evaluations” – depending on the amount of relevant data parameters available for each asset class. To qualify for the definition of a HI, an asset class must have at least three recorded condition parameters available. When less than three parameters are available, the health of an asset class is presented as a One- or Two-Parameter Assessment, as appropriate. The distinction between a “Health Index” and a “Parameter Assessment” reflects only the number of available data parameters, and should not be interpreted as indicative of superior or inferior analytical rigour and/or weight that can be put on one set of results relative to another. As we discuss later in this document, the number of condition parameters collected per asset class is often a matter of strategy, which represents a trade-off made by a utility between incremental near/medium-term planning insights and additional costs to obtain them. This consideration is clearly reflected in CNPI’s approach to asset condition parameter collection across different asset classes.

Overall Results by Asset Class

METSCO's methodology for each asset class is described in more detail in Section 3 and Section 4. The consolidated results of the Asset Condition Assessment are summarized in Figure 0-1 for distribution assets and Figure 0-2 for station assets.

Figure 0-1: Distribution Asset Health Index Results

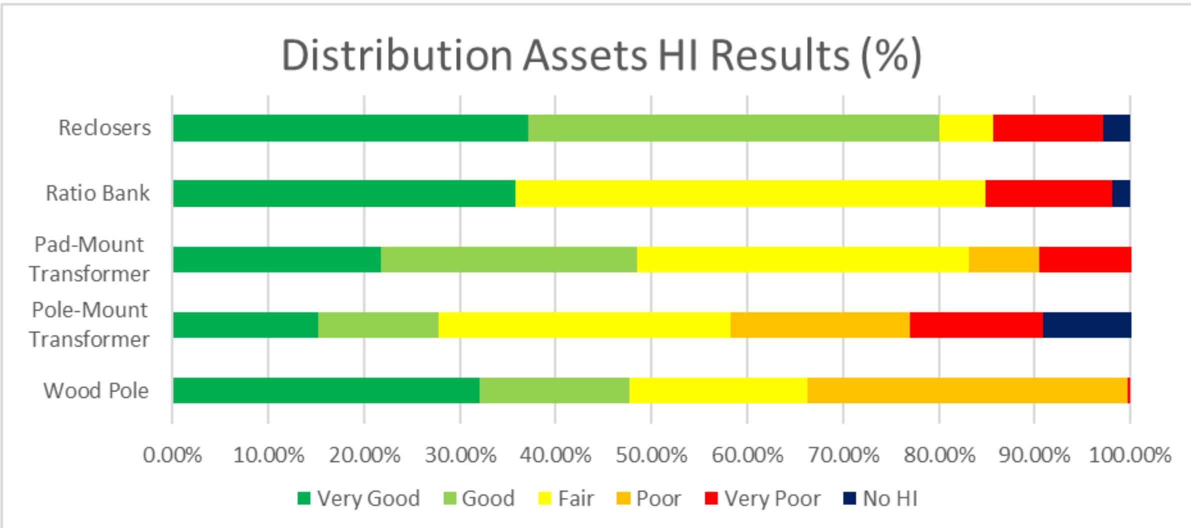
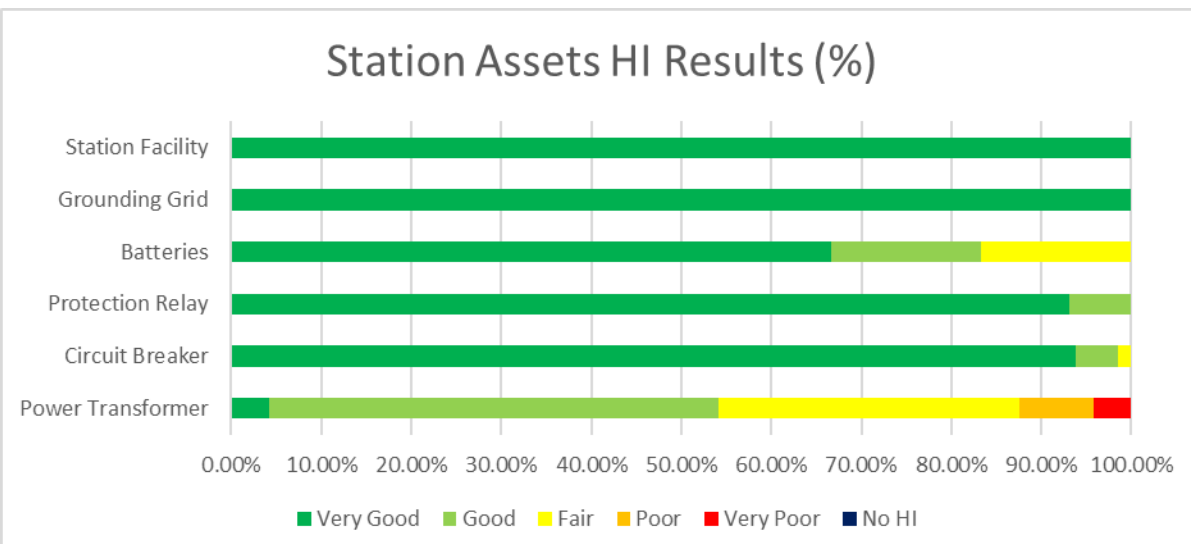


Figure 0-2: Station Asset Health Index Results



As Figure 0-1 indicates, several asset classes exhibit a significant degree of deterioration based on the results of the ACA. Most notable among them are the wood poles and pole-mount transformers. As Figure 0-2 indicates, majority of CNPI's station assets fall into Fair condition or better.

Table 0-2 presents the numerical HI summary for each asset class. The distribution of Health Indices is based on the total population count of a given asset class. For each asset class, the following details are listed: total population, average HI, average Data Availability Index (DAI), and the HI / Parameter Assessment distribution. A DAI is a percentage of condition parameter data available for an asset or asset class, as measured against the condition parameters considered in the HI Formulation. A DAI of 100% for an asset indicates that data was available for all assets and all condition parameters in an asset class. DAI is also calculated for individual condition parameters used in the HI Formulation.

Table 0-2: Asset Condition Assessment Overall results

Asset Class	Population	Health Index Distribution (Rounded %)						Average Health Index	Average DAI
		Very Good	Good	Fair	Poor	Very Poor	No HI		
Distribution Assets									
Wood Pole	23466	32.1%	15.7%	18.5%	33.4%	0.4%	0.0%	73.2%	21.0%
Pole-Mount Transformer	3795	15.2%	12.6%	30.5%	18.7%	13.0%	9.9%	51.2%	90.1%
Pad-Mount Transformer	648	21.8%	26.7%	34.7%	7.3%	0.9%	8.6%	64.1%	91.4%
Ratio Bank	53	35.9%	0.0%	49.1%	0.0%	13.2%	1.9%	62.5%	98.1%
Reclosers	35	37.1%	42.9%	5.7%	0.0%	11.4%	2.9%	77.2%	97.1%
Station Assets									
Power Transformer	24	4.2%	50.0%	33.3%	8.3%	4.2%	0.0%	70.0%	97.0%
Circuit Breaker	64	93.8%	4.7%	1.6%	0.0%	0.0%	0.0%	98.5%	43.0%
Protection Relay	29	93.1%	6.9%	0.0%	0.0%	0.0%	0.0%	96.1%	100.0%
Batteries	12	66.7%	16.7%	16.7%	0.0%	0.0%	0.0%	88.6%	89.0%
Grounding Grid	14	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	100.0%

CNPI's Current Health Index Maturity and Continuous Improvement

Data Collection Practices

We have verified that CNPI meets the minimum inspection requirements prescribed in the Distribution System Code for all asset classes this study explores. However, as discussed further in Sections 3 and 4, the amount of asset health data CNPI collects varies significantly across its asset classes. While it regularly conducts multiple empirical tests on major substation equipment such as transformers and circuit breakers and conducts multi-point visual assessments of line infrastructure (including IR scanning where applicable), CNPI employs an exception-based reporting approach towards most of its line assets. Inspecting personnel only generate asset-specific condition records when they discover an issue indicative of imminent failure (and thus requiring near-term intervention via maintenance or replacement).

An implication of the exception-based reporting approach from the perspective of HI generation is that for most of its line assets, CNPI possesses relatively few types of recorded asset-specific data aside from the year of installation, asset type/make/rating and (where relevant) historical equipment loading levels. However, another critical (and positive) implication of exception-based reporting is the comparatively low cost of inspections due to the time and effort saved in generating and analyzing physical inspection records for each asset.

Accordingly, CNPI's approach to line asset inspection data management reflects an important trade-off between the amount of asset health data available for near-term asset intervention planning, and the avoided OM&A costs that benefit its ratepayers. Although the resulting line infrastructure Health Assessments (grounded largely in asset age, excluding wood poles) incorporate less empirical tests than could be available, they are nevertheless comparable with those of other Ontario distributors of CNPI's size. Importantly, the analytical insights available from the asset health-related information that CNPI does possess, still enable it to maintain an objective and data-driven outlook on the anticipated scope and magnitude of degradation across its system in the near-to-medium term. Given that it does perform substantial empirical tests on critical station assets the failure of which could result in major reactive costs, we see CNPI's overall asset condition data collection strategy as highly pragmatic, nuanced and well-suited for a utility in its operating circumstances. We also see clear motivation to continuously improve the amount of data insights generated through its inspection practices, while remaining consistent with its overall cost management strategy.

Notwithstanding the above commentary, and consistent with our typical approach to ACA studies, Section 5 of this report lists several incremental enhancements to asset-class specific data collection practices that we see as consistent with CNPI's overall strategy and potentially worthwhile exploring in the future. In providing these recommendations, METSCO is cognizant of the fact that regulated utilities are facing cost constraints across numerous facets of their operations, while contending with the effects of ageing infrastructure, changing climate, evolving customer needs, and many other priorities. As such, adoption of any incremental enhancement to the existing asset data collection practices must be grounded in management's assessment of the incremental value of such enhancements, relative to the opportunity cost of advancements elsewhere in the utility's operations.

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1 Introduction

METSCO Energy Solutions Inc. (METSCO) is an engineering and management consulting firm specializing in work with electric and natural gas utilities. As a part of our Asset Management (AM) consulting practice we have conducted numerous Asset Condition Assessments (ACAs) commissioned by utilities, regulators, private sector power consumers, and financial institutions. Aside from the practical experience in conducting the ACA studies, METSCO's engineers made significant contributions to the development and refinement of HI methodologies across multiple asset classes through field work and a variety of R&D activities. METSCO's collective record of experience in the area of asset management for electricity transmission and distribution utilities is among the most extensive in the world, with our AM frameworks gaining acceptance across multiple regulatory jurisdictions.

Canadian Niagara Power Inc. (CNPI) is an electricity distributor operating in the Fort Erie, Port Colborne and Gananoque areas (operating as Eastern Ontario Power (EOP) in the Gananoque area). CNPI engaged METSCO to prepare a comprehensive ACA study for the assets comprising its distribution system. The ACA is expected to serve as one of the key inputs for the preparation of CNPI's five-year Distribution System Plan to be submitted to the Ontario Energy Board (OEB). The study's primary objective is to generate and report on the health of CNPI's assets in a consistent and data driven way, using the latest objective information and asset HI frameworks accepted in the industry. The ACA results are an input required to assist in future planning and prioritization of asset renewal investments. A key supplementary objective of this report is to explore potential enhancements to CNPI's asset condition data gathering practices as a part of continuous improvement work.

A dedicated ACA methodology is applied to each asset class covered in this report. The adoption of the ACA methodology requires identifying end-of-life criteria for various components associated with each asset type, followed by periodic asset inspections and recording of asset date – to identify the assets most at risk at reaching the end-of-life criteria over the relevant planning horizon. Where asset condition information is not recorded, other objective data such as asset age, make, or wear and tear sustained in operation can be used as proxies of condition, based on industry-accepted conversion scales. Each asset health criterion represents a factor that is influential, to a specific degree, in determining an asset's (or its component's) condition relative to its potential failure. These components and tests are weighted based on their importance in determining the assets' end-of-life, using METSCO's algorithms refined over time and tested in multiple regulatory proceedings.

The assets covered in the report include the following major asset classes:

- Distribution Wood Poles
- Overhead Primary Conductors
- Underground Primary Cables
- Distribution Transformers
- Distribution Ratio Banks
- Distribution Reclosers
- Station Power Transformers
- Station Circuit Breakers

- Station Protection Relays
- Station Battery Banks
- Station Grounding Grids
- Station Facilities

All the asset condition data METSCO used in its work is maintained by CNPI as part of its regular asset management activities. METSCO received CNPI's data between May 2020 and August 2020.

The report is organized into six sections including this introductory section:

- Section 2 summarizes the ISO 55000/55001/55002 standards and discusses how the ACA fits into the overall asset management framework.
- Section 3 describes the asset HI calculation methodology used by METSCO and addresses some of the common issues related to assumptions and data availability issues.
- Section 4 provides the Condition Assessment methodology framework and assessment for each of the identified asset classes.
- Section 5 summarizes METSCO's recommendations for continuous improvement efforts for the ACA.
- Section 6 summarizes METSCO's concluding remarks.

2 Context of the ACA within AM Planning

An ACA is a critical step in developing an objectively informed asset replacement strategy. An ACA study involves collection, consolidation, and utilization of the results within an organizational AM framework for the purposes of objectively quantifying and managing the risks of its asset portfolio. The level of degradation of an asset, its configuration within the system, and its corresponding likelihood of failure feed directly into the risk evaluation process, which identifies asset candidates for intervention (i.e., replacement or refurbishment). Assets are then grouped into program and project scopes that are evaluated and prioritized.

The ACA framework is designed to provide utilities with insights into the current state of an organization's asset base, the risks associated with anticipated degradation, and approaches to managing this degradation within the current AM framework, while ensuring that the organization extracts the expected value out of the asset base.

2.1 International Standards for AM

The following paragraphs serve as a brief introduction to the ISO standards and provide a brief overview of the applicability of AM standards within an entity.

The industry standard for AM planning is outlined in the ISO 5500X series of standards, which encompass ISO 55000, ISO 55001, and ISO 55002. According to these standards, each business entity finds itself at one of the three main stages along the AM journey:

1. Exploratory stage - entities looking to establish and set up an AM system;
2. Advancement stage - entities looking to realize more value from an asset base; and
3. Continuous improvement stage - those looking to assess and progressively enhance an AM system already in place for avenues of improvement.

Given that AM is a continuous improvement process, ISO 5500X remains continuously relevant within an organization; providing an objective, evidence-based framework against which the organizations can assess the managerial decisions relating to their purpose, operating context, and financial constraints over the different stages of their existence.[1]

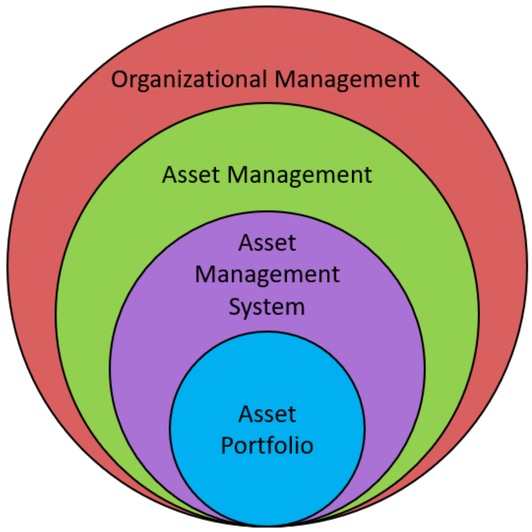
An asset is any item or entity that has a value to the organization. This can be actual or potential value, in a reliability based or monetary measure, or in other manner valuable to an organization (including intangible outcomes like public safety). The primary job of an asset manager is to extract the maximum amount of value out of the group of assets in their care. Asset managers accomplish these objectives by way of tools and processes that are collectively known as the Asset Management System or Framework. Figure 2-1 displays the key elements of such a framework expressed as a hierarchy of organizational systems. An asset portfolio, containing all known information regarding the assets, sits as the fundamental core of an organization. Around the asset portfolio, the AM System represents a set of interacting elements that establish the policy, objectives, and processes that help the organization achieve the objectives associated with preserving their assets in a working order to extract the intended value from them. The AM system is, in turn, embedded within the system AM practices – coordinated practical

[1] ISO 55000 – Asset management – Overview, principles and terminology

activities guided by the principles and processes defined in the AM System to realize the maximum value from the asset portfolio. Finally, the Organizational Management layer provides for an informed and consistent execution of the policies and processes underlying an AM System. [2]

The ACA framework is among the AM tools or procedures that enables Asset Managers to turn the known condition information into actionable insights based on the level of deterioration identified through inspections, testing, and their subsequent analysis.

Figure 2-1: Relationship between key elements of an Asset Management System[1]



2.2 Role of an ACA within the AM Process

A well-executed AM strategy hinges on the ability of an organization to classify its assets via comprehensive and extensive data and data collection procedures. This includes but is not limited to: collection and storage of technical specifications, retaining data on historical asset performance, developing frameworks for projecting future asset behaviour and degradation, maintaining information on configuration of assets relative to other elements of the system. To accomplish these objectives, AM systems seek to develop techniques and procedures by which data can be most efficiently extracted from the field then stored and retrieved when necessary to generate analytical insights. In general, with more asset data on hand, informed decisions can be made to realize greater benefits and reduce the risk across the asset portfolio managed by an organization.[3] However, as with all incremental business activities, the cost of collecting or analysing new data must be commensurate in value to the expected benefits extracted from actionable insights that the new data generates.

As a scientific and managerial discipline, AM is fundamentally concerned with evaluating the opportunities for potential asset interventions (replacement or refurbishment) from a risk-based perspective – that is the product of probability and impact of events that asset interventions seek to prevent – relative to other potential intervention candidates that can be performed at comparable cost. Accordingly, Asset

[1] ISO 55000 – Asset management – Overview, principles and terminology
[2] ISO 55001 – Asset management – Management systems – Requirements
[3] ISO 55002 – Asset management – Management systems – Guidelines for the application of ISO 55001

Management is about optimally allocating an organization's scarce capital resources across potential opportunities to reduce the risk inherent in the degradation of its assets through intervention activities that comprise AM operations and procedures. The role of an ACA study is to quantify the condition of each asset in a manner that serves to indicate its extent of degradation and failure probability.

2.3 Continuous Improvement in the AM Process

AM processes are ideally integrated throughout the entire organization. This requires a well-documented AM framework that also includes a clear and compelling expression of the organization's values in relation to how it intends to manage its assets. As a future-state goal, utilities and other organizations alike should strive to document their AM guiding principles within a Strategic Asset Management Plan (SAMP). The SAMP should be shared between all relevant agents (executive leadership, technical experts, operations and maintenance staff, or finance decision-makers) and updated on a regular basis, in order to capture the most current AM practices being implemented (including the trade-offs made in the process). Just as the asset base performance is subject to an in-depth review, the AM process and system should be reviewed with the same rigor.[1]

Asset Management should be regarded as a fluid process. Adopting a framework and an idealized set of practices does not bind the organization or restrict its agency. With time, the goal of any AM system is to continually improve and realize benefits within the organization through better management of its asset portfolio (including the insights regarding effectiveness and value for money of the AM processes themselves). Continually improved asset data and data collection procedures, updated SAMPs, and further integration into all aspects of an organization's activities as it grows and changes over time should be the goal of any AM framework.[3]

[1] ISO 55000 – Asset management – Overview, principles and terminology
[3] ISO 55002 – Asset management – Management systems – Guidelines for the application of ISO 55001

3 Asset Condition Assessment Methodology

3.1 METSCO's Project Execution

METSCO's execution path in completing the ACA study is a four-phase procedure:

1. *Initial information gathering* – including initial interviews with CNPI staff to investigate system configuration and the prominence of certain asset classes, establish the range of available condition data sources, and confirm the key assumptions regarding these factors with CNPI subject matter experts.

2. *Database construction* – activities to construct a single database of condition-related information for each CNPI asset class using the provided data sources. This includes consolidation of CNPI's asset inspection records, databases containing results of technical tests performed by CNPI staff and contractors, and other pertinent information contained in the Geographic Information System (GIS).

3. *HI and DAI calculation* – upon confirming the integrity of its condition dataset along with the accuracy of assumptions made in its preparation, METSCO calculates the Health Indices and DAI for all asset classes. This also involved several verification steps with CNPI's SMEs to ensure that METSCO correctly interpreted the data records and was aware of the reasoning for any exceptions.

4. *Results Reporting* – the final phase of the project scope was the creation of the ACA report and sharing of the results with the CNPI staff and Senior Management.

3.2 Data Sources

To establish the unit demographics of CNPI's system assets, METSCO was provided with CNPI's asset demographic data from its GIS. At a minimum, the data contains information on asset identifier, vintage, model, and year of commissioning which served as the primary asset reference library for the analysis.

To assess the condition of CNPI's system, METSCO was provided with historical asset inspection and maintenance data for each asset class. Most of the data came from primary sources such as equipment inspection forms completed by CNPI staff or contractors, or the results of specific tests. In addition to the inspection, testing and demographic data contained in the GIS, CNPI provided METSCO with historical operating data stored in other relevant IT/OT system – most notably the loading information for power transformers.

3.3 Asset Condition Assessment Methodologies

Prior to completing an ACA, a methodology needs to be selected for the current entity. The four most common methodologies that can be employed to assess the condition of the system health include:

1. Additive models – asset degradation factors and scores are used to independently calculate a score for each individual asset, with the HI representing a weighted average of all individual scores from 0 to 100;

2. Gateway models – select parameters deemed to be most impactful on the asset's overall functionality act as "gates" to drive the overall condition of an asset, by effectively "deflating" the scores of other (less impactful) components;
3. Subtractive models – consider that a relatively Poor condition for any of several major assets within a broader system of assets could act as a sufficient justification to drive investments into the entire system; and
4. Multiplicative models – a model that dynamically shifts the calculation towards specific degradation factors, if they are a leading indicator to show that an asset is failing.

The additive and gateway models are typically used for assessing individual assets, whereas the subtractive and multiplicative models are typically used for aggregate and composite system-level assessments. The latter models are still in an early stage and require extensive refinement and validation to confirm their applicability. The gateway model assigns gates to criteria or asset subcomponents which are difficult or expensive to replace and maintain, and/or are known to be a major cause of asset malfunctioning. This methodology is commonly used in conjunction with the additive model for major assets such as wood poles, where a "gate" score will act to reduce the HI due to a low recorded score for a given criterion. For example, if the remaining strength of a wood pole is less than 60%, the final HI for that asset is halved.

Most distribution utilities employ an additive model with selective gateway model elements. METSCO selected this approach when conducting the ACA, which is in alignment with most of CNPI's peer utilities.

It is also important to note that in cases where a utility does not possess at least three different asset health parameters for a given asset class, we refer to the resulting health calculation as a One- or Two-Parameter Health Assessment rather than a HI. This distinction in nomenclature is entirely a function of reporting clarity rather than a commentary on sufficiency of information to make observations about health of a given asset class. In METSCO's view, an index is a product of multiple inputs, and as such, it is not an appropriate term to describe a result of an assessment based on a single data input or even a pair of inputs.

Notwithstanding the above distinction, METSCO emphasizes that a higher number of inputs does not necessarily equate to higher quality or value of the health assessment. Like any economic activities, condition data collection, storage and analysis have cost implications, often in the form of OM&A expenditures that are passed on to ratepayers on a dollar-for-dollar basis. Accordingly, a decision to collect and keep track of any incremental data parameter across a population of assets carries significant cost implications for a utility and its customers.

3.4 Overview of Selected Methodology

3.4.1 Condition Parameters

To assess the health for a given asset class, formulations are developed based on condition parameters that can be expected to contribute to the degradation and eventual failure of that type of an asset. A weight is assigned to each condition parameter to indicate the amount of influence the condition has on the overall health of the asset. Figure 3-1 exemplifies a HI formulation table.

Figure 3-1: HI Formulation Components

Degradation Factor:
The asset aging mechanisms, tests, or failure modes.

Condition Indicator Numerical Score:
The converted numerical score associated with the degradation factor, which corresponds directly with the indicator letter score.

Condition Max Score:
The highest obtainable Score for each degradation factor. (4 x Weight)

#	Degradation Factor	Weight	Condition Indicator Letter Score	Condition Indicator Numerical Score	Condition Max Score
1	Degradation Factor 1	4	A-E	4-0	16
2	Degradation Factor 2	6	A,C,E	4,2,0	24
3	Degradation Factor 3	6	A-E	4-0	24
				Asset Max Score	64

Condition Weight:
The impact of the condition with respect to asset failure and/or the safe operation of the asset. Higher impact results in higher weight

Condition Indicator Letter Score:
The letter grade associated with the degradation factor – this is typically captured from the raw inspection data.

Asset Max Score:
The highest numerical grade that can be assigned to the asset / asset class, given the associated degradation factors and weights.

Condition parameters of the asset are characteristic properties that are used to derive the overall HI. Condition parameters are specific and uniquely graded to each asset class. Additionally, some condition parameters can be comprised of sub-condition parameters. For example, the oil quality condition parameter for a station power transformer is based on multiple sub-condition parameters such as the acidity of the oil, its interfacial tension, dielectric strength, and water content.

The scale used to determine an asset's score for a condition parameter is called the "condition indicator". Each condition parameter is ranked from A to E and each rank corresponds to a numerical grade. In the above example, a condition score of 4 represents the best grade, whereas a condition score of 0 represents the worst grade.

A – 4 Best Condition
B – 3 Normal Wear
C – 2 Requires Remediation
D – 1 Rapidly Deteriorating
E – 0 Beyond Repair

3.4.2 Use of Age as a Condition Parameter

Some industry participants question the appropriateness of including age as a potential condition parameter for calculating asset HI values. At the core of the argument against the use of age in calculating asset condition is the notion that age implies a linear degradation path for an asset that does not always match the actual experience in the field.

While some assets lose their structural integrity faster than would be expected with the passage of time, others, such as those with limited exposure to natural environmental factors, or those that benefitted from regular predictive and corrective maintenance, may retain their original condition for a longer period of time than age-based degradation would imply. In recognition of the argument as to the limitations of age-based condition scoring, METSCO attempts to limit the instances where it relies on only age as a parameter explicitly used in the HI formulation.

In some cases, however, the limited number of condition parameters available for calculation of asset health makes age the only viable proxy for condition degradation. In other cases, such as when assessing condition of complex equipment containing a number of internal mechanical components that degrade with continuous operation and the state of which cannot be assessed without destructive testing, age represents an important component of asset health calculation irrespective of the number of other factors that may be available for analysis.

In the specific case of CNPI, age is one of or the only available condition parameters for several line infrastructure asset classes, and as such – a dominant determinant of the reported condition, based on the appropriate formulation that translates calendar age into a specific condition score. While having additional asset condition data where age is the only available metric would enable CNPI to derive additional and/or more precise insights about the state of their plant, a decision to collect more asset health information is a strategic trade-off that utilities' management should make on balance of all costs and benefits. This includes the opportunity cost of work elsewhere on the system foregone and/or deferred to enable data collection, and the expected benefits associated with newly collected data. In lieu of other available data and given CNPI's current asset management strategy where a large portion of line assets are managed on a Run to Failure basis, age makes up a reasonable proxy for condition of assets within the same asset class relative to one another. As CNPI's asset management strategy evolves, we expect that CNPI may consider expanding the scope of data collection as well as equipment testing.

3.4.3 Implications of CNPI's Current Approach to Asset Data Collection

To be worthwhile of the incremental cost and effort, the collection and analysis of any new asset health data must give the utility confidence that the benefits of the resulting insights can lead to commensurate value gains. In cases where available spending levels limit the amount of inspection / testing work a utility can perform in a given year, management must prioritize among asset classes where more information is advisable, and those where lack of medium-longer-term planning precision can be a tolerable risk. In our interviews with CNPI, we have confirmed that the utility's management applies this reasoning to the scoping of its inspection activities and setting of the associated budgets.

This approach is evident in practice when considering the relative number of testing and inspection data parameters available for CNPI's major substation assets, where the utility collects substantially more condition data than it does for its linear infrastructure. Importantly, the relative lack of linear infrastructure health data records does not correspond to a lack of diligence in asset management. In the case of CNPI (and multiple other Ontario distributors) it continues to rely on an Exception-Based approach to equipment deficiency reporting for overhead and underground line assets. This approach entails making a specific record of an asset's health parameters only when inspection reveals deficiencies indicative of imminent failure and/or other potential hazards requiring near-term rectification (e.g. safety issues or significant vegetation encroachments). Relying on data drawn from the Exception Records, CNPI creates work orders to rectify the identified issues in the near term (prioritizing them based on relative urgency and other relevant operating factors.

Accordingly, while the Exception-Based asset health reporting approach does not generate records that could be used to generate Health Indices for an entire population of assets, it relies on modern multi-point inspection methodologies and relies on testing tools like IR scan guns where appropriate. As such, this approach ensures that all assets are inspected in accordance with the DSC requirements, all imminent issues are addressed in a timely manner, while managing the utility's overall inspection and testing budget. Inherent in this approach is an implicit trade-off between the precision of asset intervention planning over a medium/longer term and the rate impact of inspection work. Considering that CNPI's asset management approach for certain components of line infrastructure has largely relied on either deficiency-based replacement driven by the Exception-Based reporting described above, or a Run to Failure approach, METSCO sees the current approach to asset inspection and asset data record keeping as a reasonable exercise of management's discretion.

3.4.4 Final Health Index Formulation

The final HI, which is a function of the condition scores and weightings, is calculated based on the following formula:

$$HI = \left(\frac{\sum_{i=1} Weight_i * Numerical\ Grade_i}{Total\ Score}\right) x\ 100\%$$

Where *i* corresponds to the condition parameter number, and the HI is a percentage representing the remaining life of the asset.

A gating approach is used for condition parameters that have a significant influence on the health of an asset. If the condition parameter that has been flagged as a gating parameter is below a pre-defined threshold value, the overall HI is reduced by 50%. This approach enables utilities to efficiently flag severely degraded assets through identification of condition parameters acknowledged to be critical indicators of overall asset health.

3.4.5 Health Index Results

METSCO's assessment of asset condition uses a consistent five-point scale along the expected degradation path for every asset, ranging from Very Good to Very Poor. To assign each asset into one of the categories, METSCO constructs an HI formulation for each asset class, which captures information on individual degradation factors contributing to that asset's declining condition over time.

Condition scores assigned to each degradation factor are also expressed as numerical or letter grades along with pre-defined scales. The final HI – expressed as a value between 0% and 100% - is a weighted sum of scores of individual degradation factors, with each of the five condition categories (Very Good, Good, Fair, Poor, Very Poor) corresponding to a numerical band. For example, the condition score of Very Good indicates assets with HI values between 100% and 85%, whereas assets found to be in a Very Poor condition score are those with calculated HI values between 0% and 30%. Generating an HI provides a succinct measure of the long-term health of an asset. Table 3-1 presents the HI ranges with the corresponding asset condition, its description as well as implications for asset intervention prior to failure.

Table 3-1: HI Ranges and Corresponding Asset Condition

HI Score (%)	Condition	Description	Implications
[85-100]	Very Good	Some evidence of aging or minor deterioration of a limited number of components	Normal Maintenance
[70-85)	Good	Significant Deterioration of some components	Normal Maintenance
[50-70)	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on the unit's criticality
[30-50)	Poor	Widespread serious deterioration	Start the planning process to replace or rehabilitate, considering the risk and consequences of failure
[0-30)	Very Poor	Extensive serious deterioration	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment

3.5 Data Availability Index

To put the calculation of HI values into the context of available data, METSCO supplemented its HI findings with the calculation of the DAI: a measure of the availability of the condition parameter data for a specific asset weighted by each condition parameter to the HI score. The DAI is calculated by dividing the sum of the weights of the condition parameters available to the total weight of the condition parameters used in the HI formulation for the asset class. The formula is given by:

$$DAI = \left(\frac{\sum_{i=1} Weight_i * \alpha_i}{\sum_{i=1} Weight_i}\right) x\ 100\%$$

Where *i* corresponds to the condition parameter number and α is the availability coefficient (equals 1 when data available and equals 0 when data unavailable).

An asset with all condition parameter data available will have a DAI value of 100%, independent of the asset's HI score. Assets with a high DAI will correlate to HI scores that describe the asset condition with a high degree of confidence. For distribution assets – typified by relatively large asset populations – if the DAI for an asset is less than 70%, a valid HI cannot be calculated. The subset of distribution assets without a valid HI are assigned an extrapolated HI value using the valid HI results for assets within the same asset class and ten-year age band. Similarly, for station assets – typified by relatively small asset populations – if the DAI for an asset is less than 65%, a valid HI cannot be calculated. HI results for station assets are not extrapolated due to the small population and higher complexity of equipment (and thus potential asset health issues).

4 Health Assessment Formulations and Results

This section presents the applied health assessment formulation for each asset class, the derived assessment results, and the data available to perform the study.

4.1 Distribution Assets

4.1.1 Wood Poles

Table 4-1: Wood Pole Assessment Formulation

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Remaining Pole Strength *	8	A,B,C,D,E	4,3,2,1,0	32
Wood Rot	6	A,C,E	4,2,0	24
Insect Damage	1	A,C,E	4,2,0	4
Woodpecker Damage	1	A,C,E	4,2,0	4
Crack Damage	1	A,C,E	4,2,0	4
Defects / Other Damages	1	A,C,E	4,2,0	4
Age	3	A,B,C,D,E	4,3,2,1,0	12
Out of Plumb	2	A,C,E	4,2,0	8
**gateway applied*			Total Score	**92**

Wood poles are an integral part of any distribution system. They are the support structures for overhead distribution system. Wood, being a natural material, has degradation processes that are different from other assets in distribution systems. The most critical degradation process for wood poles involves biological and environmental mechanisms such as fungal decay, wildlife damage, and weather effects which can impact the mechanical strength of the pole. Pole failures are among the most consequential events from the perspective of public safety. The remaining strength condition parameter is a quantitative measurement that provides adequate evidence of the deterioration of the operational health of the asset.

The HI for wood poles is calculated by considering a combination of end-of-life criteria summarized in Table 4-1. The HI formulation is a combination between the additive and gateway model; with the gateway applied to the remaining strength with a pass test check. When the remaining strength for a pole is below 60% and/or the recorded pass test is tagged as *Fail*, the final HI for that pole is reduced by half. This is in alignment with CSA standard C22.3 no. 1, where it states that any pole with a remaining strength less than 60% of its design strength to be replaced or reinforced[5].

Additional condition parameters include service age, wood rot presence, mechanical defects, and the leaning of wood poles. A visual inspection record notes the degree of wood rot/decay developed on the pole’s external surface, internal cross-section, and cross-arm sections. The presence of wood rot signifies there is a high moisture content surrounding the pole and may impact the pole’s strength. Additionally, visual inspections note for the following mechanical defects found on wood poles:

- Cracks
- Insect / Woodpecker Damage
- Fire Damage

[5] *Overhead Systems*, CAN/CSA C22.3 No.1-15, 2015

- Deformations

CNPI owns 23,467 wood poles within its service territory, of these 20,516 are in the Niagara region and 2,951 are in the EOP region. Figure 4-1 presents the age for Niagara wood poles and Figure 4-2 presents the age for EOP wood poles.

Figure 4-1: Niagara Wood Poles Age Demographics

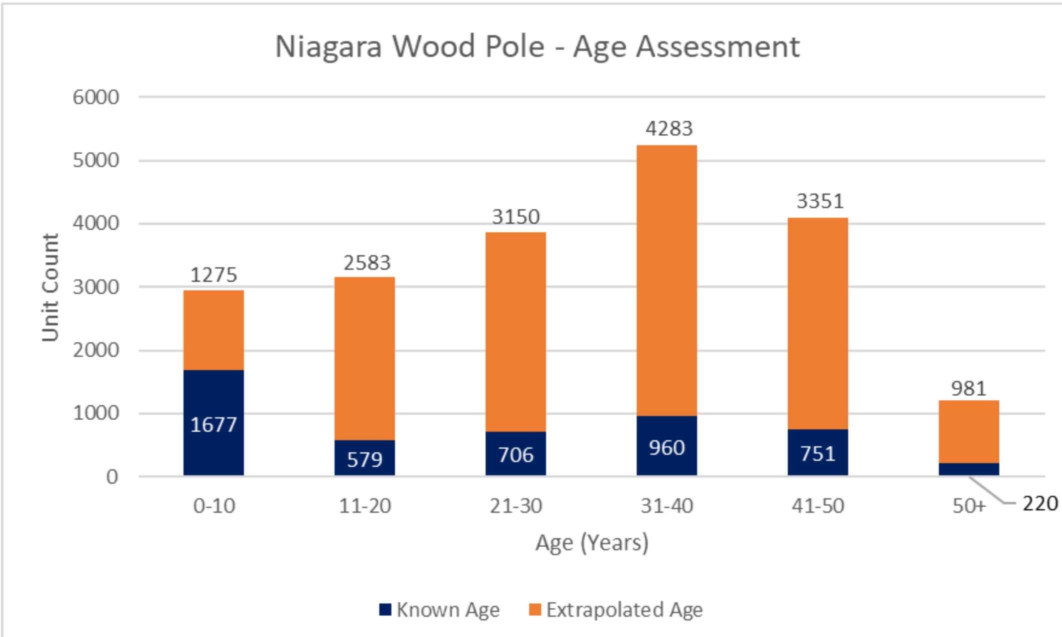
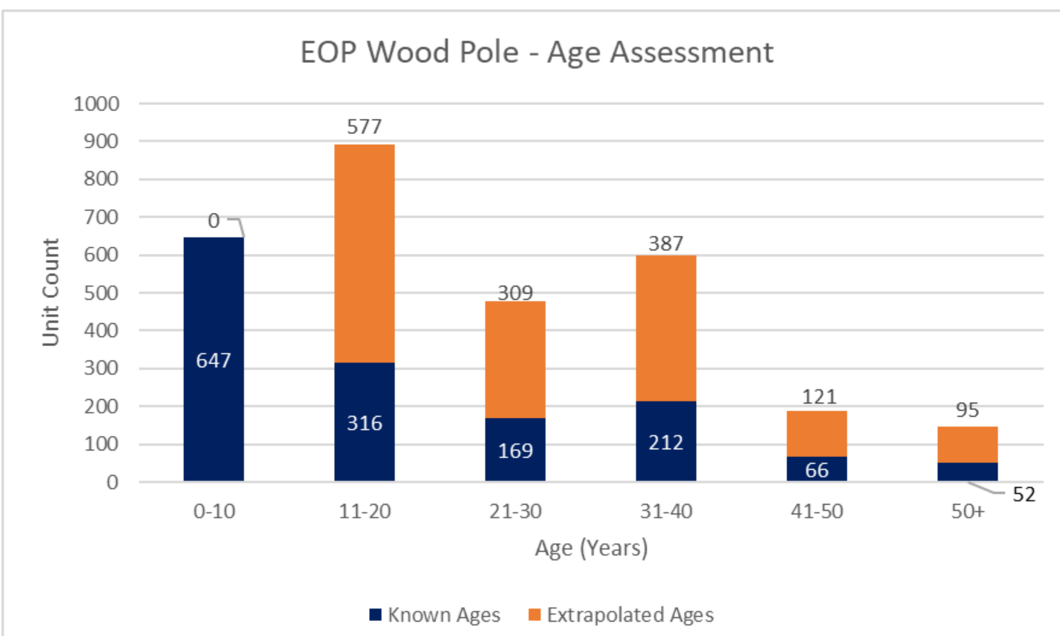
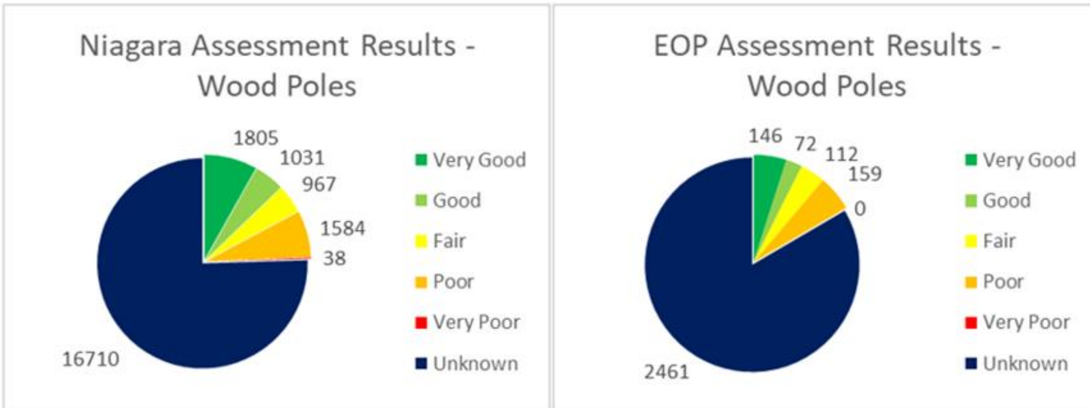


Figure 4-2: EOP Wood Poles Age Demographic



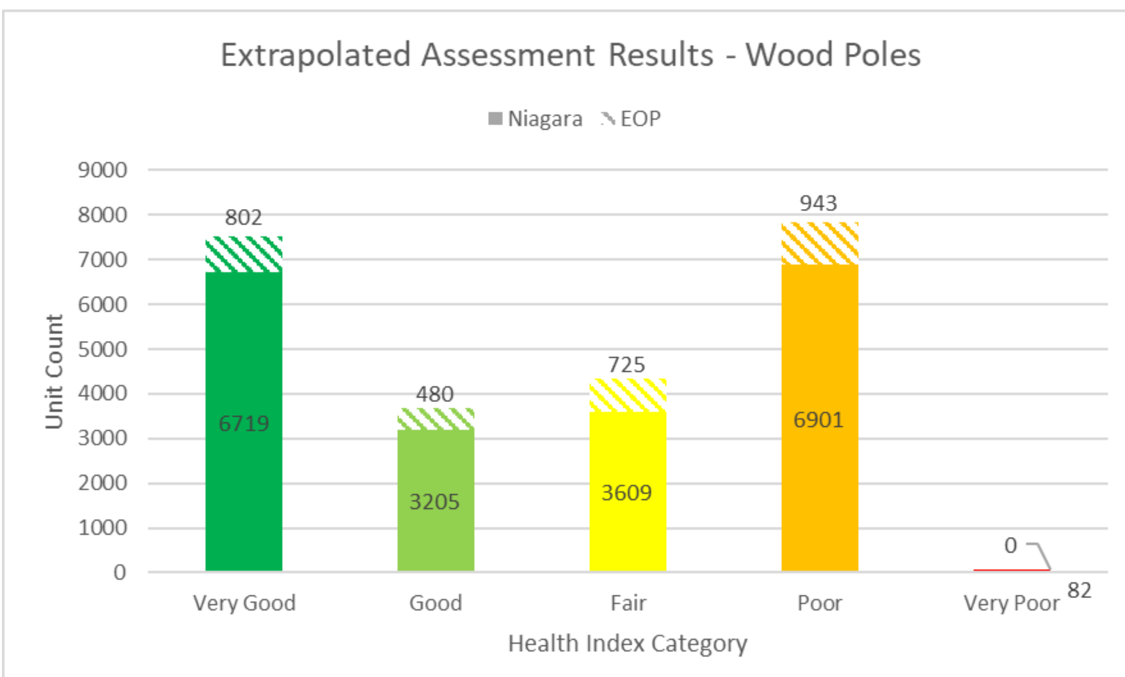
CNPI's pole inspection records, test results, and nameplate data were used to calculate the HI based on the criteria provided in Table 4-1. Figure 4-3 presents the results of METSCO's assessment for the wood poles asset class with no extrapolation.

Figure 4-3: Niagara and EOP Wood Pole Assessment Results



To assess the complete population of wood poles, the HI for the remaining Niagara and EOP wood poles are extrapolated based on the HI distribution of the known population by each age group. The extrapolated HI results for wood poles is presented in Figure 4-4. Most of the poles are in or above the Fair category condition with 33.78% of the total population being in Poor or Very Poor condition.

Figure 4-4: Extrapolated Wood Pole Assessment Results



The average DAI for wood poles, excluding poles with no calculated result, is 98.5%. Table 4-2 presents the DAI of each parameter used to assess wood poles in the current framework.

Table 4-2: Wood Pole Condition Parameters Data Availability

Condition Parameter	% of Assets with Data
Remaining Pole Strength	100%
Wood Rot	96%
Insect Damage	96%
Woodpecker Damage	96%
Crack Damage	100%
Defects / Other Damages	100%
Service Age	100%
Out of Plumb	100%

4.1.2 Overhead Primary Conductors & Underground Primary Cables

CNPI manages and maintains approximately 936 km of overhead primary conductors. Overhead primary conductors transmit electricity from substations to customer premises and are supported by poles. The HI formulation for overhead primary conductors are largely driven by two parameters – age and conductor size.

Laboratory tests are available to determine the tensile strength and assess the remaining useful life of conductors. However, distribution line conductors are rarely tested given the cost considerations involved. As such, these tests are typically reserved for larger and more expensive transmission conductors. An appropriate proxy for the tensile strength of the conductor and to determine the remaining life of the asset is the use of service age. However, for this assessment, there is no easy access to extract the relevant age distribution from CNPI's database therefore, no assessment is completed.

Additionally, CNPI provided information pertaining to their overhead wire sizes. An undersized conductor (applicable to the largely obsolete #2 - #6 copper conductors) presents a risk to the utility in its daily operations. Undersized conductors carrying large loads can result in sub-optimal system operation due to high line losses and are susceptible to frequent breakdowns. In the Niagara region, there are 0.45% and 3.37% of wires are #4 CU and #6 CU respectively. In the EOP region 0.25% of wires are #6 CU. This accounts for an approximate total of 30 km.

Like overhead conductors, underground cables also transmit electricity within the electrical distribution system, however, they are located below ground. Compared to overhead lines, they are less susceptible to weather fluctuations, external contacts such as tree branches and vegetation and are in general affected by fewer outage types. However, distribution underground cables are more expensive and are one of the more challenging assets in electricity systems from a condition assessment and asset management viewpoint. Several test techniques, such as partial discharge (PD) and water tree diagnostic testing have become available over recent years to identify the condition and performance of the asset class. Some tests can be destructive to the asset and hence are used less frequently. Accordingly, the preference is given to non-destructive testing such as Hi-Pot testing. In the absence of these tests, a sampling methodology can be executed to determine the general condition of the asset.

CNPI manages and maintains approximately 101 km of underground primary cable within its service territory. No assessment is completed for the asset class.

4.1.3 Overhead Distribution (Pole Mount) Transformer

Table 4-3: Pole Mount Transformer Assessment Formulation

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Age	3	A,B,C,D,E	4,3,2,1,0	12
			Total Score	**12**

Overhead (pole mount) transformers are installed on service poles to step down power from the medium voltage distribution system to the final voltage rating for customer use. To assess the health for pole mount transformers, only one-parameter was used. In this case, the one parameter is service age, shown in Table 4-3.

CNPI owns 3,795 pole mount transformers within its service territory, 3,249 in the Niagara region and 546 in the EOP region. Installation dates are known for 94% of Niagara transformers and 31.1% of EOP transformers. For unknown installation dates of Niagara pole mount transformers, the age is estimated to be the average age of installed pole mount transformers on the same feeder. For unknown installation dates of EOP pole mount transformers, the age cannot be estimated with a high confidence. Figure 4-5 and Figure 4-6 presents the age distribution for pole mount transformers for Niagara and EOP respectively.

Figure 4-5 presents the results of METSCO's assessment for the pole mount transformers asset class. Most of the transformers are Fair or better condition with 31.78% of the total population being in Very Poor condition based on recorded and assumed service ages.

Figure 4-5: Niagara Pole Mount Transformers Age Demographic

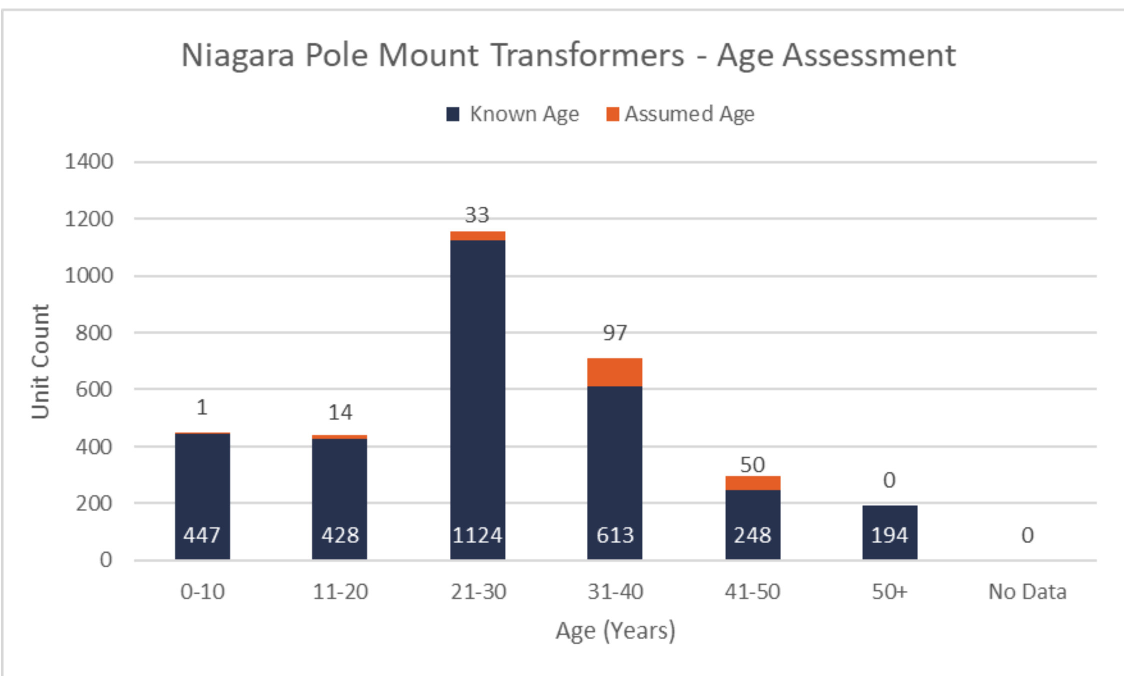


Figure 4-6: EOP Pole Mount Transformers Age Demographic

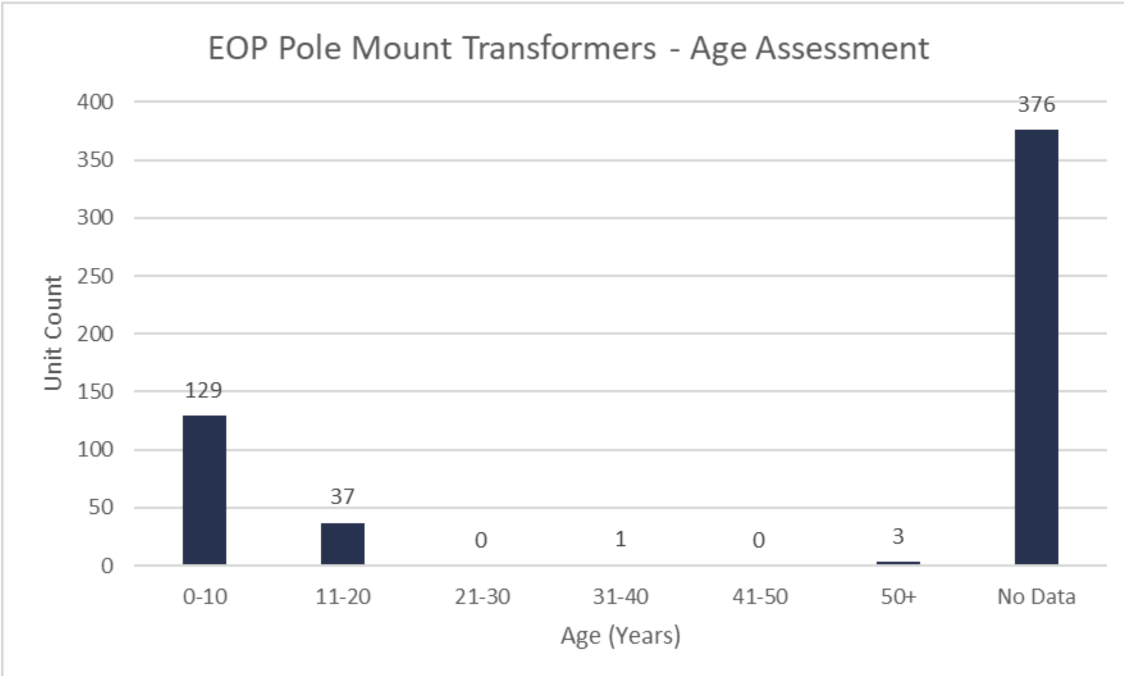


Figure 4-7: Extrapolated Pole Mount Transformer Assessment Results

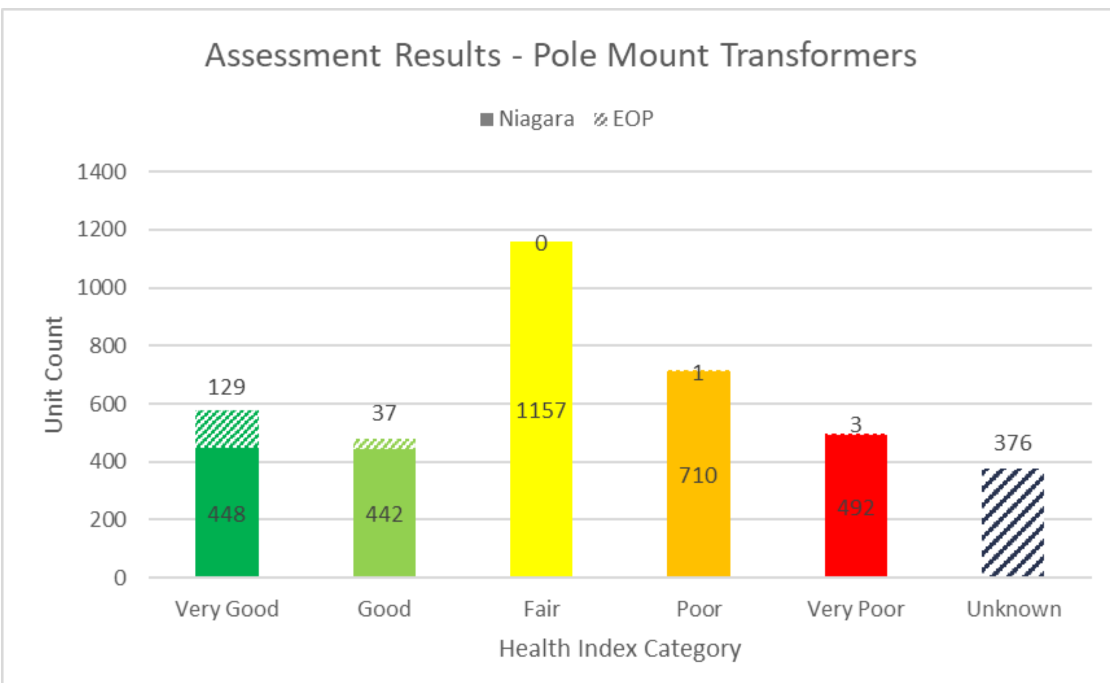


Table 4-4 presents the DAI of each parameter used to assess pole mount transformers in the current framework.

Table 4-4: Pole Mount Transformer Condition Parameters Data Availability

Condition Parameter	% of Assets with Data
Service Age	84.9%

4.1.4 Distribution (Pad Mount) Transformer

Table 4-5: Pad Mount Transformer Assessment Formulation

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Age	3	A,B,C,D,E	4,3,2,1,0	12
			Total Score	**12**

Pad mount distribution transformers are utilized for similar functionalities as pole mount transformers. They step down power from the medium voltage distribution system to the final utilization voltage for the customer; however, they are located below ground or on the ground level. To assess the health for pad mount transformers, only one-parameter was used. In this case, the one parameter is service age, shown in Table 4-5.

CNPI owns 648 pad mount transformers within its service territory, 572 in the Niagara region and 76 in the EOP region. Installation dates are known for 98% of Niagara transformers and 26.3% of EOP transformers. For unknown installation dates of Niagara transformers, the age is estimated to be the average age of installed pad mount transformers on the same feeder. For unknown installation dates of EOP pad mount transformers, the age cannot be estimated with a high confidence. Figure 4-8 and Figure 4-9 presents the age distribution for pad mount transformers for Niagara and EOP regions, respectively.

Figure 4-10 presents the results of METSCO's assessment for the pad mount transformers asset class. Most of the transformers are in Fair or better condition with 8.18% of the total population being in Very Poor condition.

Figure 4-8: Niagara Pad Mount Transformers Age Demographic

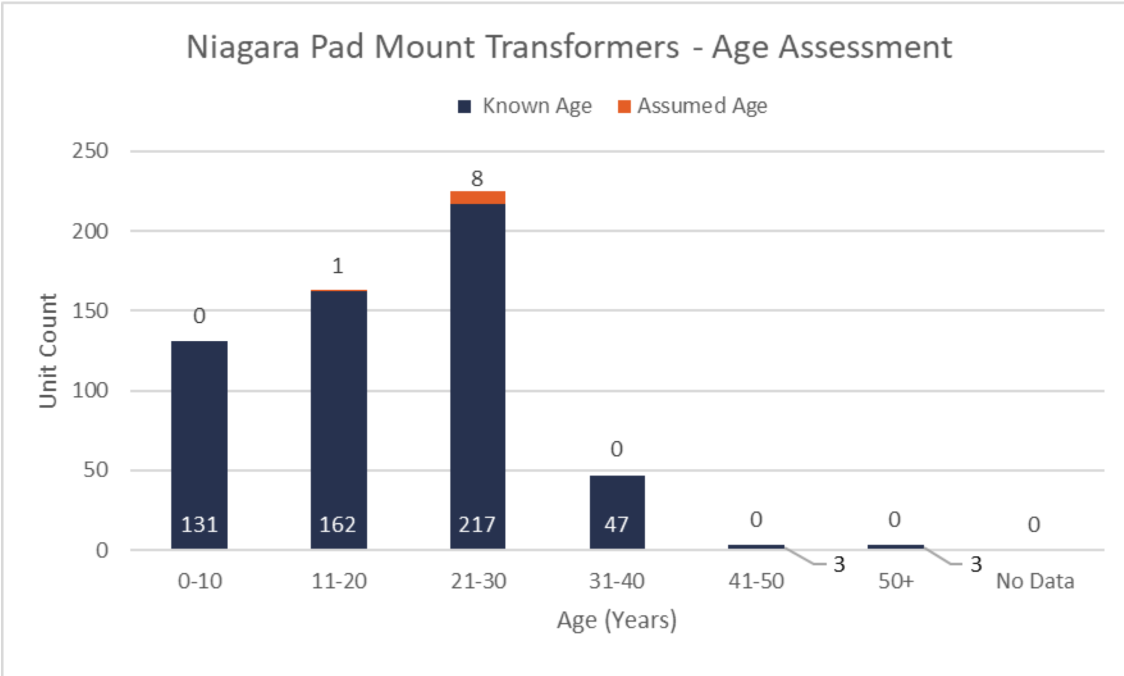


Figure 4-9: EOP Pad Mount Transformers Age Demographic

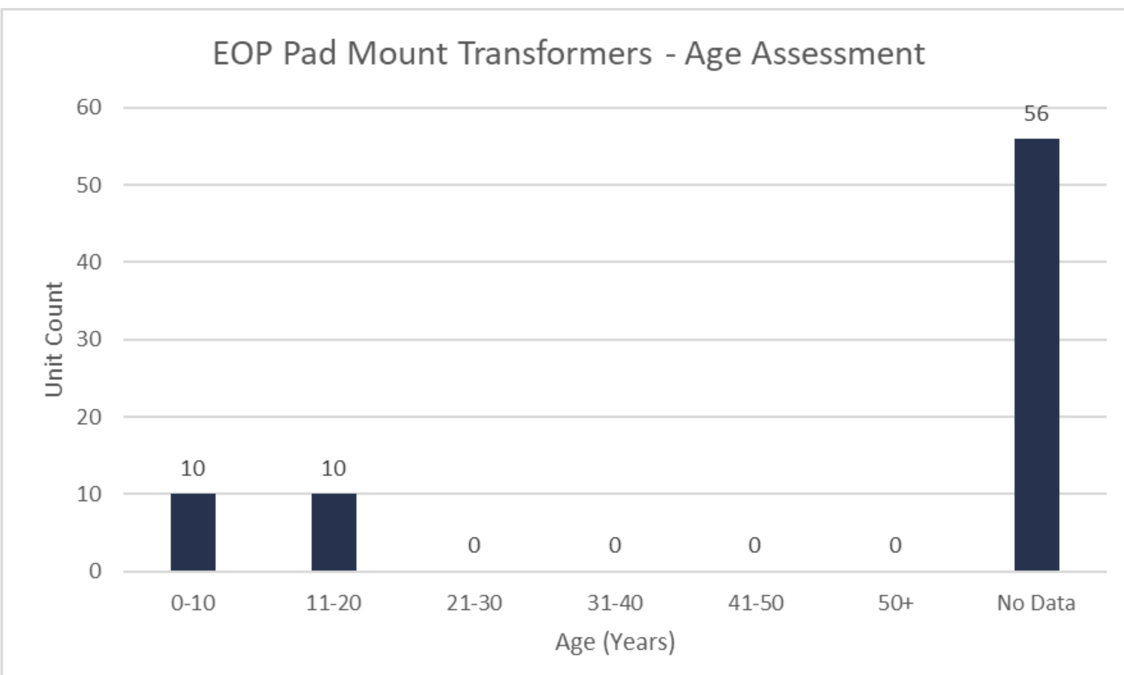


Figure 4-10: Extrapolated Pad-Mounted Transformer Assessment Results

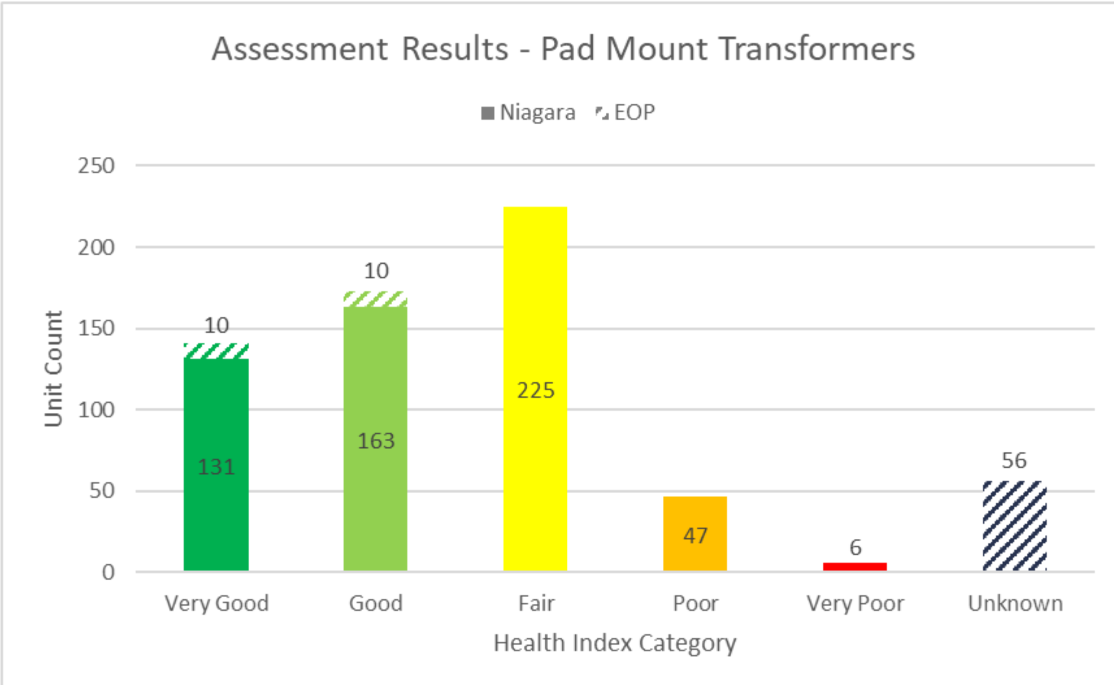


Table 4-6 presents the DAI of each parameter used to assess pad mount transformers in the current framework.

Table 4-6: Pad Mount Transformer Condition Parameters Data Availability

Condition Parameter	% of Assets with Data
Service Age	89.6%

4.1.5 Ratio Banks

Table 4-7: Ratio Bank Health Assessment Formulation

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Age	3	A,B,C,D,E	4,3,2,1,0	12
			Total Score	**12**

Ratio banks are transformers that are installed in sets of 1 or 3 that serve a similar purpose to substations, supplying pockets of lower voltage and/or delta-connected load that have not yet been converted. Only one-parameter was used to assess the health of ratio banks. In this case, the one parameter is service age, shown in Table 4-7.

CNPI owns 53 ratio banks within its service territory 49 in the Niagara region and 4 in the EOP region. Figure 4-11 and Figure 4-12 presents the age distribution for ratio banks for Niagara and EOP respectively.

Figure 4-13 presents the results of METSCO's assessment for the ratio banks asset class. Most of the ratio banks are in Fair or better condition with 13.21% of the total population being in Very Poor condition.

Figure 4-11: Niagara Ratio Bank Age Demographic

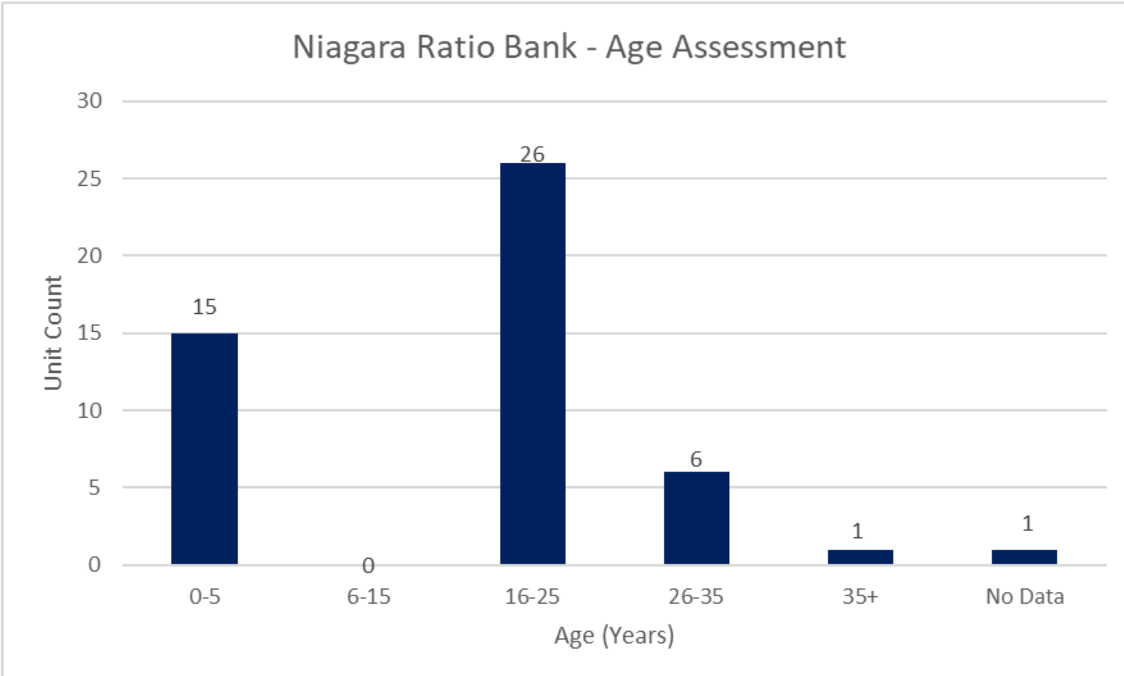


Figure 4-12: EOP Ratio Bank Age Demographic

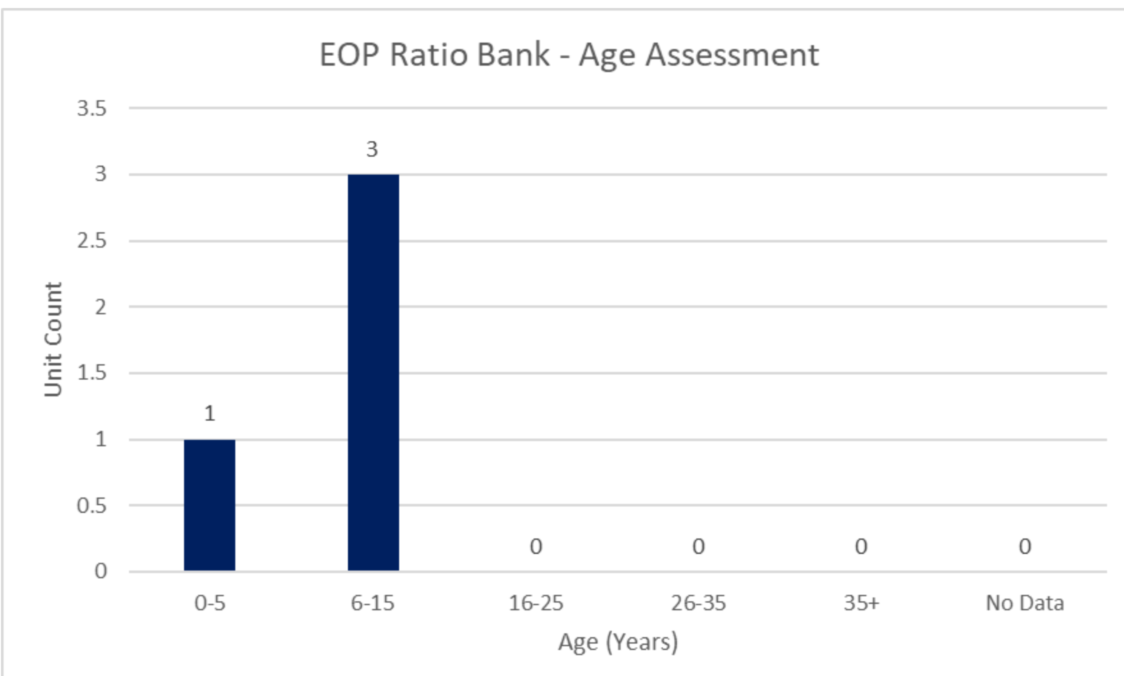


Figure 4-13: Extrapolated Ratio Bank Assessment Results

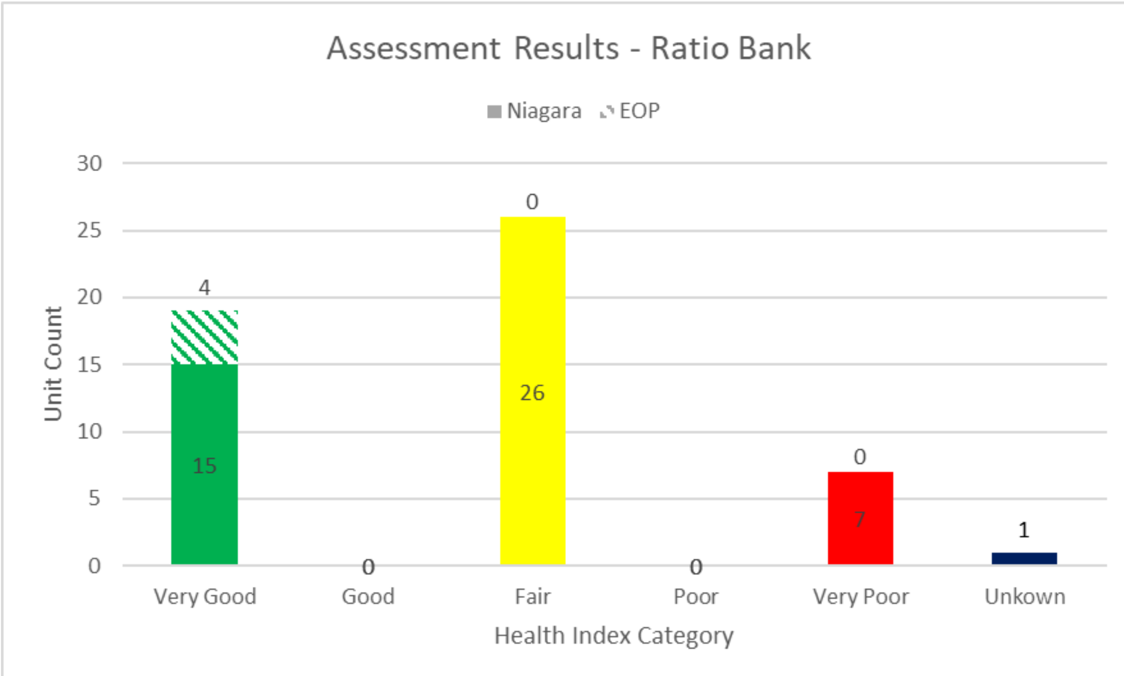


Table 4-8 presents the DAI of each parameter used to assess ratio banks in the current framework.

Table 4-8: Ratio Bank Condition Parameters Data Availability

Condition Parameter	% of Assets with Data
Service Age	98.1%

4.1.6 Reclosers

Table 4-9: Reclosers Assessment Formulation

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Age	3	A,B,C,D,E	4,3,2,1,0	12
			Total Score	**12**

Reclosers function like circuit breakers, but often equipped with control unit for single- or multi-shot reclosing of the feeder. CNPI's nameplate information was used to calculate the one-parameter assessment based on the criteria provided in Table 4-9.

CNPI owns 35 reclosers within its service territory all in the Niagara region. Figure 4-14 presents the age distribution for reclosers. Figure 4-15 presents the results of METSCO's assessment for the substation reclosers. Most of the reclosers are in Very Good or Good condition with five units assessed to be in Very Poor condition.

Figure 4-14: Reclosers Age Demographic

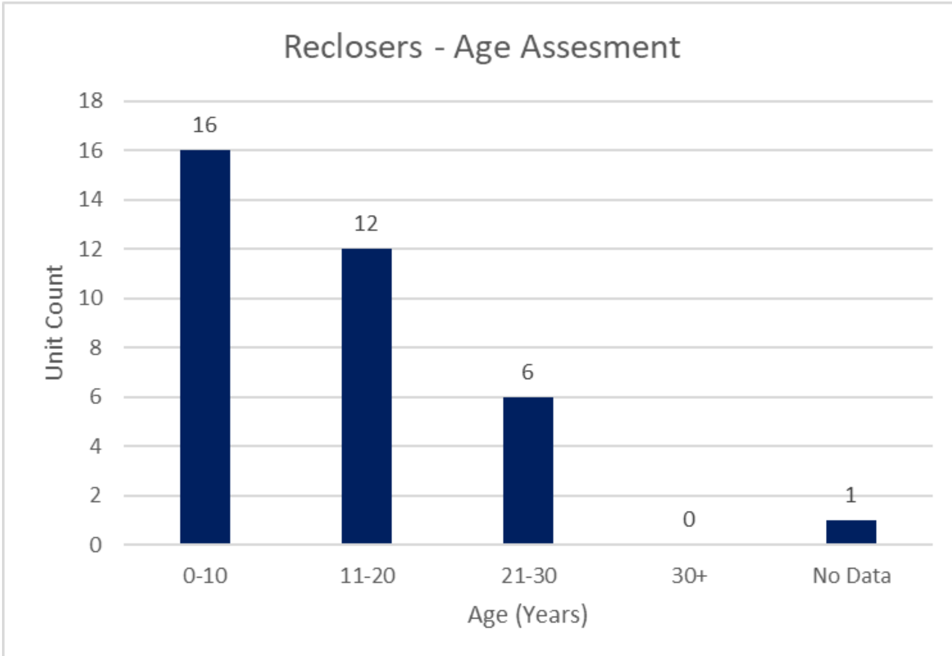


Figure 4-15: Reclosers Assessment Results

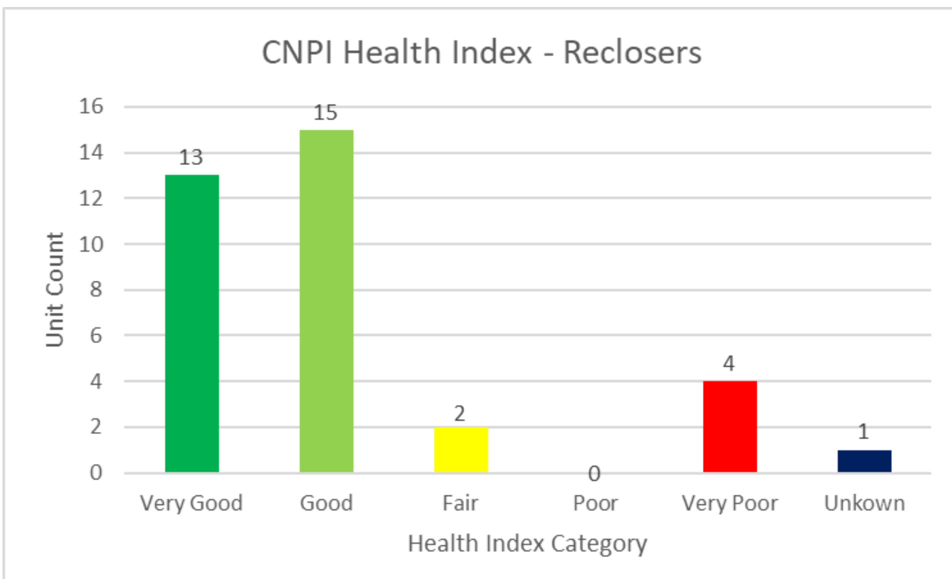


Table 4-10 presents the percentage of data availability of each parameter used to assess reclosers in the current framework.

Table 4-10: Reclosers Condition Parameters Data Availability

Condition Parameter	% of Assets with Data
Service Age	97.1%

4.2 Station Assets

4.2.1 Power Transformers

Table 4-11: Power Transformer Assessment Formulation

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Dissolved Gas Analysis*	10	A,B,C,D,E	4,3,2,1,0	40
Load History	10	A,B,C,D,E	4,3,2,1,0	40
Insulation Power Factor	10	A,B,C,D,E	4,3,2,1,0	40
Insulation Moisture Content	10	A,B,C,D,E	4,3,2,1,0	40
Oil Quality*	8	A,C,E	4,2,0	32
Degree of Polymerization (or Age)	6	A,B,C,D,E	4,3,2,1,0	24
Overall Condition	6	A,B,C,D,E	4,3,2,1,0	24
Foundation Condition	1	A,B,C,D,E	4,3,2,1,0	4
Oil Leaks	1	A,E	4,0	4
**gateway applied*			Total Score	**248**

Power transformers in the distribution system are housed within substations. They are used to step down the voltage within the distribution system to supply end users. Computing the HI of a transformer requires developing end-of-life criteria for its various components. Table 4-11 summarizes the HI formulation used for oil-type power transformers. Four parameters are determined by quantitative testing results, with each parameter carrying a weight of eight or ten. These measurements include dissolved gas analysis, insulation power factor, insulation moisture content and oil quality. Each of these parameters represents an aspect of a power transformer with a direct impact on the operational health of the asset. In addition, loading history, age and visual inspection results of transformer conditions were used to calculate the HI Score.

By performing the dissolved gas analysis (DGA), it is possible to identify the precursor conditions of internal faults such as arcing, partial discharge, low-energy sparking, severe overloading, and overheating in the insulating medium. Insulation power factor measurements are an important source of data to monitor transformer and bushing conditions. Lower scores for one or a combination of these condition parameters strongly indicate progressed degradation of the asset, hence their larger weights. Oil leaks and overall condition of components are collected by visual inspection and serve as indicators of the total health of the asset.

Although load history is not a test, it holds value as an input for the HI algorithm. The rate of insulation degradation is directly related to the operating temperature which is directly related to transformer loading levels. The peak loading level of the transformers is expressed in a percentage of the nameplate rating. CNPI collects the substation load history monthly, recording the monthly peak for each month.

Another useful indication of transformer condition is insulation moisture content. Insulation provides several functions from acting as a dielectric to isolating different internal components of a transformer. As a transformer ages, this insulation can become saturated with water and compromise the reliability of the transformer. This is an important parameter to monitor when considering the overall health of power transformers. CNPI owns 24 oil-type power transformers, 19 in the Niagara region and five in the EOP region. Figure 4-16 presents the age profile of power transformers in-service. The HI distribution for in-service power transformers is presented in Figure 4-17. CNPI's inspection records, test results, and operation data were used to calculate the HI based on the criteria provided in Table 4-11. Most of the power transformers are in Good condition with an average HI score of 70% across the asset class.

Figure 4-16: Power Transformer Age Demographic

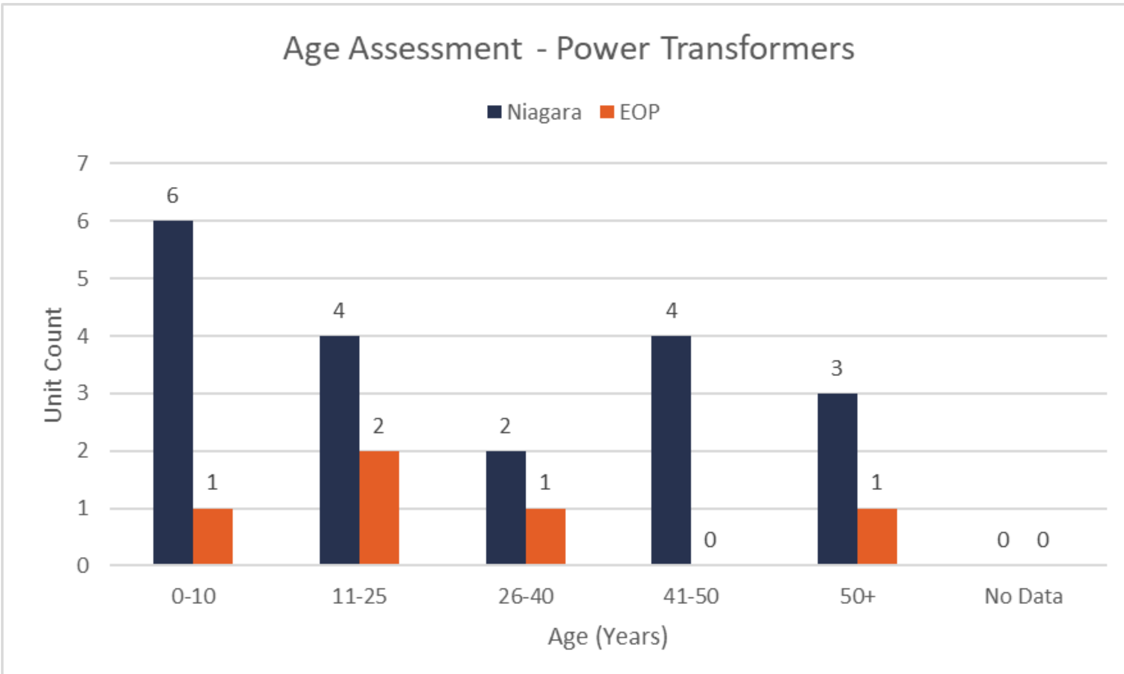


Figure 4-17: Power Transformer Assessment Results

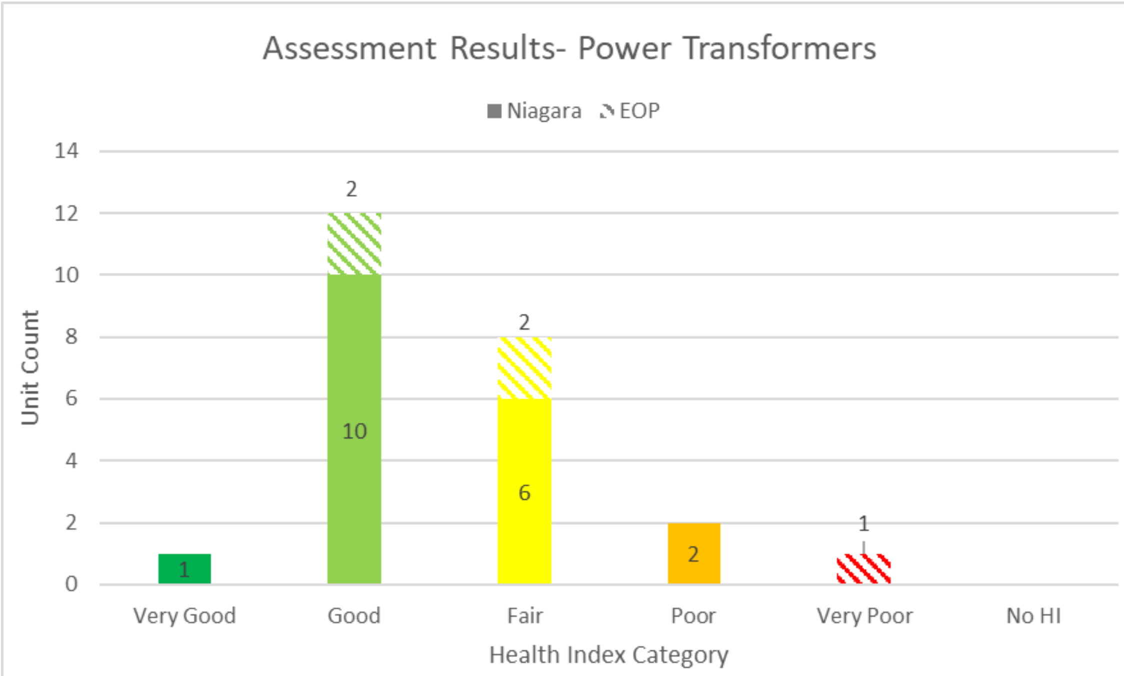


Table 4-12 presents the percentage of data availability of each parameter used to assess power transformers in the current framework. The DAI for station power transformers is 98.7%.

Table 4-12: Power Transformer Condition Parameters Data Availability

Condition Parameter	% of Assets with Data
Dissolved Gas Analysis	100%
Load History	96%
Insulation Power Factor	96%
Insulation Moisture Content	96%
Oil Quality	100%
Degree of Polymerization (or Age)	100%
Overall Condition	100%
Foundation Condition	100%
Oil Leaks	100%

4.2.2 Circuit Breakers

Table 4-13: Circuit Breaker Assessment Formulation

Degradation Factor	Type	Weight	Ranking	Numerical Grade	Max Score
Overall Condition	All	4	A,B,C,D,E	4,3,2,1,0	16
Timing/Travel Tests	All	3	A,B,C,D,E	4,3,2,1,0	12
Contact Resistance Tests	Air/SF_6/ Vacuum	2	A,B,C,D,E	4,3,2,1,0	8
SF_6 Gas Analysis	SF_6	3	A,B,C,D,E	4,3,2,1,0	12
			Total Score	**Air**	**36**
				SF_6	**48**
				Vacuum	**36**

Station circuit breakers are a critical substation asset and are the primary protective device for maintaining public safety and protecting other station equipment. Breakers work with station relays, to open either in a fault situation or as directed by the operations center or automation. Breaker degradation occurs primarily through physical processes, such as by way of corrosion, accumulation of debris on insulators, or due to operations under load. In general, the more load passing through the asset when the breaker operates the more wear and tear it sustains. Several types of breakers are available, with the primary difference being the medium used to break up the current – including traditional oil breakers or vacuum bottle insulated with SF6 gas or solid dielectric insulation. The HI for substation circuit breakers is calculated by considering a combination of test results, number of operations and visual inspections as summarized in Table 4-13.

CNPI owns 64 circuit breakers, 50 in the Niagara region and 14 in the EOP region. Figure 4-18 presents the age distribution for circuit breakers. CNPI's inspection records, testing results, and nameplate information were used to calculate the HI based on the criteria provided in Table 4-13. Figure 4-19 presents the results of METSCO's assessment for the substation circuit breakers. All circuit breakers are in Very Good or Good condition with one Niagara unit found to be in Fair condition.

Figure 4-18: Circuit Breaker Age Demographic

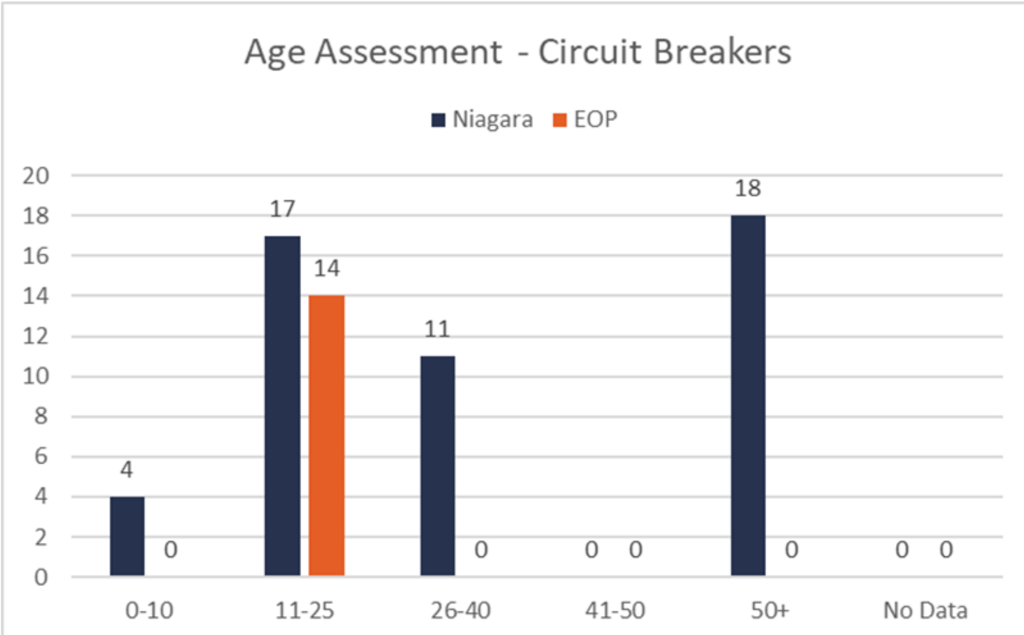


Figure 4-19: Circuit Breakers Assessment Results

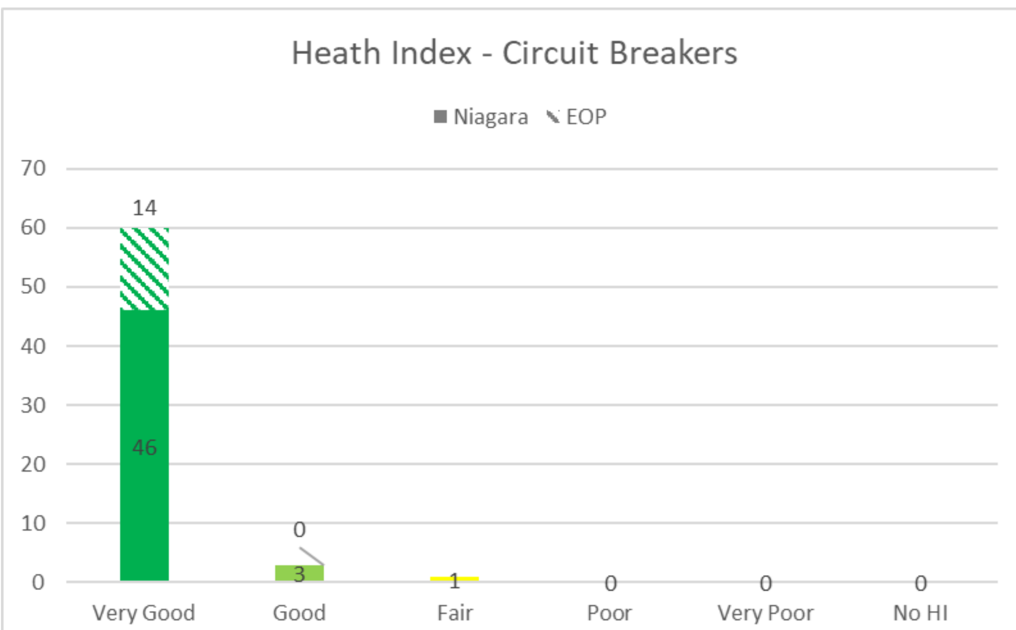


Table 4-14 presents the percentage of data availability of each parameter used to assess circuit breakers in the current framework.

Table 4-14: Circuit Breakers Condition Parameters Data Availability

Condition Parameter	% of Assets with Data		
	Vacuum	Air	SF6
Overall Condition	100%	100%	100%
Contact Resistance	0%	0%	46%
Timing Test	0%	0%	46%
SF6 Test			46%

4.2.3 Protection Relays

Table 4-15: Protection Relays Assessment Formulation

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Overall Condition	3	A,B,C,D,E	4,3,2,1,0	12
Service Age	4	A,B,C,D,E	4,3,2,1,0	16
			Total Score	**28**

The function of protection relays in distribution systems is to detect abnormal operating conditions and initiate a recloser trip to isolate faulty circuits from healthy circuits. Protection relays obtain their input from instrument transformers, process the information, and automatically take corrective action with adequate speed and selectivity.

The health assessment for reclosers is calculated by considering two parameters that are collected by CNPI, shown in Table 4-15.

CNPI owns 29 protection relays, 22 in the Niagara region and seven in the EOP region. Figure 4-20 presents the age distribution for protection relays. CNPI's inspection records and nameplate information were used to calculate the health of the asset based on the criteria provided in Table 4-15. Figure 4-21 presents the results of METSCO's assessment for the substation protection relays. All protection relays are assessed to be in Very Good or Good condition.

Figure 4-20: Protection Relay Age Demographics

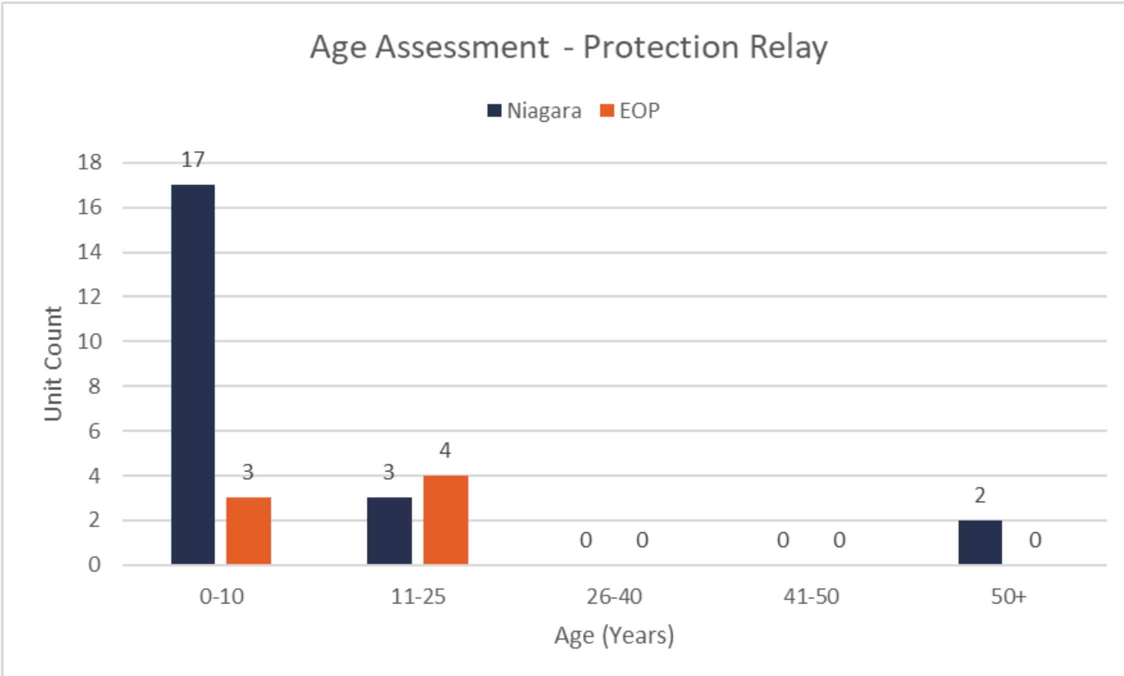


Figure 4-21: Protection Relays Assessment Results

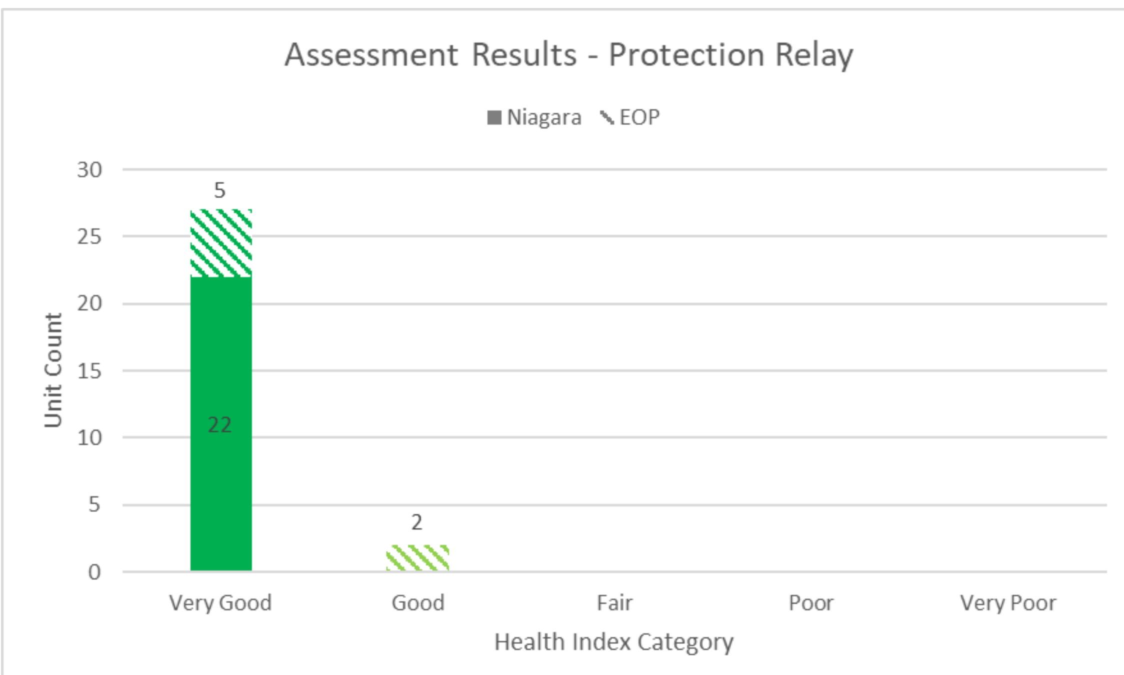


Table 4-16 presents the percentage of data availability of each parameter used to assess protection relays in the current framework.

Table 4-16: Protection Relay Condition Parameters Data Availability

Condition Parameter	% of Assets with Data
Service Age	100%
Overall Condition	100%

4.2.4 Battery Banks

Table 4-17: Battery Bank Assessment Formulation

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Age of Battery/Charger	4	A,B,C,D,E	4,3,2,1,0	16
Testing	4	A,C,E	4,3,2,1,0	16
Overall Condition	4	A,B,C,D,E	4,3,2,1,0	16
			Total Score	**48**

The purpose of substation batteries is to supply control power to essential station functionalities such as lighting, communication, and protection/control equipment in the event of a loss of supply to the station. Batteries are carefully sized to store adequate energy for system operation during an AC power failure. The main components of the battery system are the charger and the battery bank which is comprised of several battery cells in series.

Both the electrodes and electrolyte in control batteries undergo aging with repeated charge and discharge cycles, which result in a gradual reduction of battery storage capacity. The end of life is reached when the battery is no longer able to retain adequate charge for required functions. Battery chargers can experience component failures, but these can be easily replaced, resulting in instances of chargers frequently outlasting the battery units.

To assess the health of battery banks and chargers, the unit's age, test results, and visual inspection results are considered. The first condition parameter is age, which provides insight into the remaining useful life of the asset based on the typical useful lives of DC systems seen across the industry. Batteries also operate based on a determinate chemical process, which has a known lifetime and useful duration. Discharge testing provides detail on individual cell charges, total voltage, and discharge rates as the battery supplies energy over time. Any atypical degradation of a battery bank's performance will be seen with this testing procedure. The output voltage and float voltage of the battery charger are also tested. Table 4-17 summarizes the methodology to generate the HI for station battery banks.

CNPI owns 12 battery banks within its stations, 9 in the Niagara region and 3 in the EOP region. Figure 4-22 presents the age distribution for battery banks. The battery test results, inspection records and nameplate information for CNPI's battery banks were used to calculate the HI based on the criteria listed in Table 4-17. Figure 4-23 presents the results of METSCO's assessment for the substation batteries and chargers. All units are assessed to be in Very Good or Good condition with two units falling in the Fair category.

Figure 4-22: Battery Age Demographics

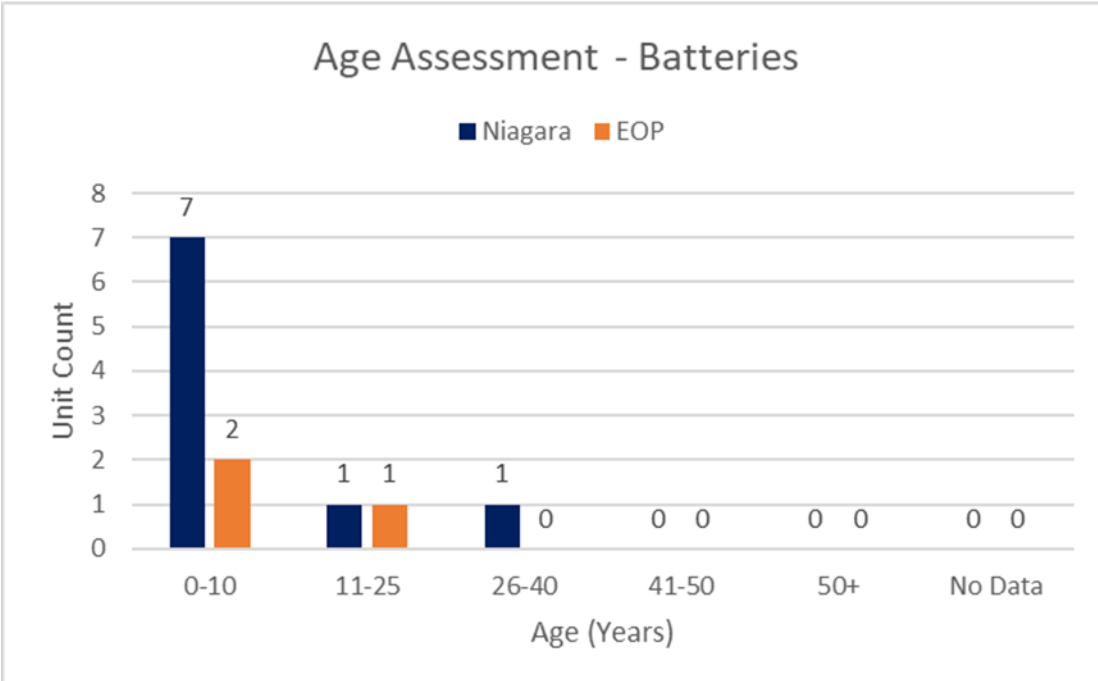


Figure 4-23: Battery Assessment Results

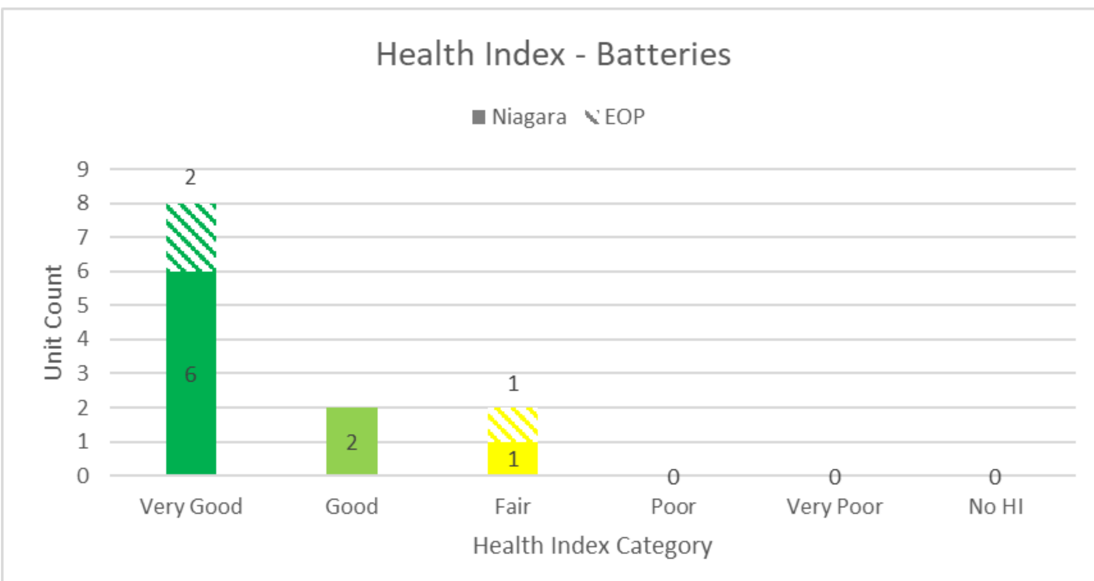


Table 4-18 presents the percentage of data availability of each parameter used to assess station batteries in the current framework.

Table 4-18: Battery Condition Parameters Data Availability

Condition Parameter	% of Assets with Data
Service Age	100%
Testing	67%
Overall Condition	100%

4.2.5 Grounding Grids

Table 4-19: Grounding Grid Assessment Formulation

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Overall Condition	3	A,B,C,D,E	4,3,2,1,0	12
			Total Score	**12**

The purpose of a substation ground grid is to provide a low resistance ground electrode for system neutral, for equipment case grounding and to maintain safe potential gradients within the station yards during abnormal operating conditions, i.e. line-to-ground faults.

CNPI owns 14 grounding grids, 11 and the Niagara region and three in the EOP region. Figure 4-24 presents the age distribution for grounding grids. CNPI's maintenance records and nameplate information were used to calculate the HI based on the criteria provided in Table 4-19. Figure 4-25 presents the results of METSCO's assessment for the substation grounding grids. All grounding grids are assessed to be in Very Good condition.

Figure 4-24: Ground Grid Age Distribution

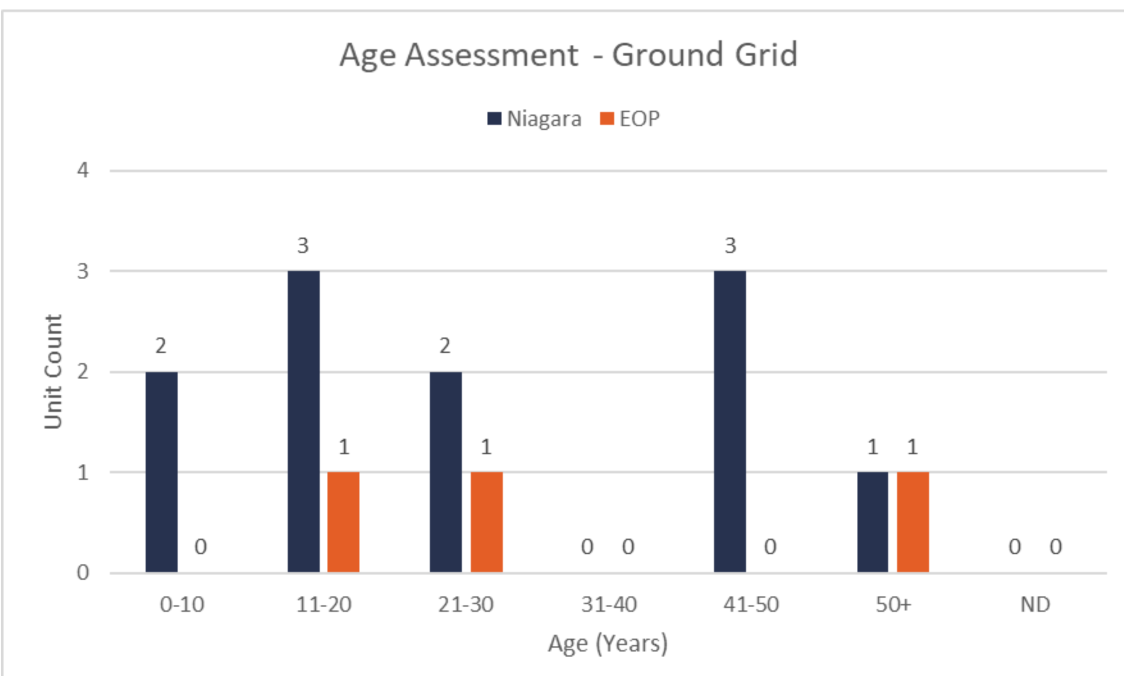


Figure 4-25: Ground Grid Assessment Results

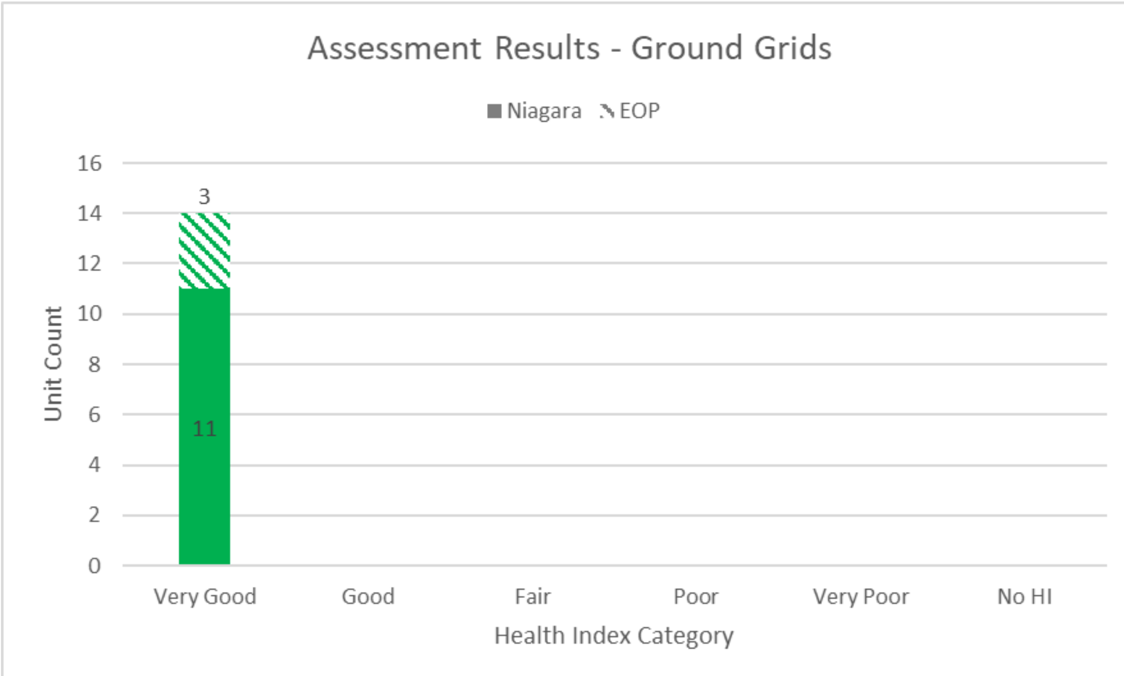


Table 4-20 presents the percentage of data availability of each parameter used to assess station ground grids in the current framework.

Table 4-20: Ground Grid Condition Parameters Data Availability

Condition Parameter	% of Assets with Data
Overall Condition	100%

5 Recommendations

A complete ACA framework for CNPI represents an integral component of its broader AM framework, enabling it to proactively manage its distribution assets and ensure that the right actions are taken for the right assets at the right time. This framework leveraged the information captured from maintenance programs and other utility records, creating an essential linkage between the ongoing maintenance activities and the capital investment decision-making process. Leveraging these insights allows for CNPI's investment decision-making to be further enhanced with the relevant information regarding the state of the assets. However, there are opportunities to improve the current ACA framework.

This section breaks down METSCO's recommendations into the following categories:

1. HI improvements
2. Data availability improvements

5.1 Health Index Improvements

The following set of recommendations target additional condition parameters that can be incorporated for specific asset classes. The recommendations are based on improving the ACA framework over time and should not be interpreted as suggesting that immediate action is warranted. The following tables highlight the condition parameter name with a short description of the reasoning to include the condition parameter.

<u>Underground Primary Cables</u>

Table 5-1: Data Collection Recommendation for Underground Primary Cable

Criteria	Reasoning
Service Age	Knowledge of service age of cables would allow focus on the oldest cables for future inspections.
Cable Failure	Identifying water tree samples throughout the service territory and varying age, the utility would be able to have an improved view on cable conditions within the system.
Loading History	Cable degradation can also occur due to overheating under overloading or short circuit conditions. Over stressing of insulation during voltage surges can also lead to cable failures.

<u>Overhead Primary Conductors</u>

Table 5-2: Data Collection Recommendation for Overhead Primary Conductors

Criteria	Reasoning
Service Age	Knowledge of service age of cables would allow focus on the oldest cables for future inspections.

Pole Mount and Pad Mount Distribution Transformers

Table 5-3: Data Collection Recommendation for Overhead Distribution Transformer

Criteria	Reasoning
Visual Inspection	To identify if the transformer is subject to any physical damage, oil leak, or corrosion.
Loading Data	Transformer degradation can also occur due to overheating under overloading conditions.

Power Transformers

Table 5-4: Data Collection Recommendation for Power Transformers

Criteria	Reasoning
Infrared Scanning	To identify if the transformer is operating within normal temperature ranges – excess temperature would require further investigation.

Circuit Breakers

Table 5-5: Data Collection Recommendation for Circuit Breakers

Criteria	Reasoning
Contact Resistance Test	Low percentage of circuit breakers underwent this test. Defective contacts lead to higher losses and may result in arcing or other incidents. Identification of this condition parameter over time provides degradation information of an asset.
Timing/Travel Test	Low percentage of circuit breakers underwent this test. Timing/ Travel test provides information as to whether the breaker's operating mechanism is operating properly. Identification of operation use over time provides degradation information of an asset.
Infrared Scanning	To identify if the circuit breaker is operating within normal temperature ranges – excess temperature would require further investigation.

Reclosers

Table 5-6: Data Collection Recommendation for Reclosers

Criteria	Reasoning
Visual Inspection	To identify if the reclosers is subject to any physical damage, loss of insulation, mechanical failures, looseness, corrosion or overheating that could cause the reclosers to fail.
Counter Readings	To determine what percentage of the maximum rated operation suggested by manufacturer is being used. High usage could require better monitoring.

Protection Relays

Table 5-7: Data Collection Recommendation for Protection Relays

Criteria	Reasoning
Defect and Test Reports	Objective asset tests with output results identify asset conditions over time.
Mean Time Between Failures	Objective asset tests with output results identify asset conditions over time.
Discretionary Obsolescence	Refers to a utility's own decision grounded in a policy or standard change to phase out a certain type of equipment.
Non-Discretionary Obsolescence	Is a function of certain relay units exceeding the term of their extended support / warranty by vendors, compatibility issues between a given relay type and the utility's evolving communications network, or the availability of replacement parts for a given relay type to enable refurbishment of in-service units.

Ground Grid

Table 5-8: Data Collection Recommendation for Ground Grids

Criteria	Reasoning
Surface Stone Resistivity	Corroded surface stone with lower resistivity can impose safety concerns or hazards. The identification of this condition parameter over time provides degradation information of the ground grid.
Grid and Bond Integrity	Broken conductors or connectors of the ground grid after the operability of the ground grid during a fault. The identification of this condition parameter over time provides degradation information of the ground grid.
Current Injection Test	The current injection test provides information as to whether the ground currents flow into the earth without creating hazardous over-voltages. Identification of operation use over time provides degradation information of an asset.

5.2 Data Availability Improvements

Data availability is critical to produce prudent, accurate, and justified decision-making outputs. It represents the single most important element that can influence the degree to which the AM decision-making relies on objective factors. Companies understand that it is critical to execute continuous improvement procedures through an AM data lifecycle, such that data gaps and inaccuracies can be addressed and mitigated. In the case of any condition assessment, the quality is dependent on the available data. For condition parameters with low data availability METSCO recommends that CNPI continue collecting, storing, and managing the information of their assets.

Additionally, for an asset to have a valid HI, it must meet a minimum 70% of available data across the condition parameters used in the HI formulation for distribution assets and 65% for station assets. We recommend that CNPI explore the opportunity of capturing asset data for condition parameters with limited data throughout the asset population, such that valid Health Indices can be produced across the population. It is anticipated that with every passing year, the inspection record database will continue to grow, allowing for Health Indices to be calculated for the remaining population.

Overall, METSCO recommends that CNPI continues to work on mitigating the current data gaps identified in this report so as to enhance their insights of their asset population. METSCO believes CNPI's testing, inspection, and maintenance programs are well-positioned to continue to capture this information using processes and technologies in place within the organization.

6 Conclusions

The preceding report highlights several asset classes being assessed of their condition as managed by CNPI. Among the notable successes of CNPI is their continuous effort in managing their wood pole population proactively to limit the number of Very Poor units to be in service. At the same time the observed condition of certain line asset classes suggests that higher replacement volumes and creative cost-effective approaches to gain further insights about the relative state of individual assets in the Poor, Very Poor and No Data categories appear desirable.

Furthermore, the focus on condition monitoring of major substation equipment appears to be paying off given the current HI results in particular station power transformers. This can indicate CNPI has taken steps to effectively manage the station assets health to deliver the expected performance by CNPI's customer base.

We recommend that CNPI explores a balance between deploying resources dedicated to active System Renewal work, while introducing any incremental (and invariably focused) insights regarding the asset base's health stemming from modest enhancements to the existing practices. This will allow to maximize the value of information that becomes available from time to time through normal operations. The report highlights a number of improvement that CNPI's asset management staff can further explore and demonstrate their commitment to continuous improvement and enhancement to asset decision-making based on a clear sense of strategic trade-offs.

This concludes our Asset Condition Assessment report. METSCO thanks the CNPI management team for the opportunity to conduct this study and the professional support shown to our staff throughout the project's duration.

Appendix A – Condition Parameters Grading Tables

Wood Poles

Table A-1: Criteria for Remaining Pole Strength

Condition Rating	Corresponding Condition
A	Remaining strength more than 90%
B	Remaining strength more than 80% and up to and including 90%
C	Remaining strength more than 70% and up to and including 80%
D	Remaining strength more than 60% and up to and including 70%
E	Remaining strength less than or equal to 60%

Table A-2: Criteria for Wood Rot

Condition Rating	Corresponding Condition
A	No decay
B	Top decay, Cavity
C	Groundline decay, Bad shell
D	Heart rot
E	Bad Rot, Hollow

Table A-3: Criteria for Defects - Insects

Condition Rating	Corresponding Condition
A	No insects
B	Ants on pole
C	Carpenter ants, Insect infest., Termites
D	Insect damage

Table A-4: Criteria for Defects - Woodpecker

Condition Rating	Corresponding Condition
A	No Woodpecker
C	Woodpecker

Table A-5: Criteria for Defects – Cracks

Condition Rating	Corresponding Condition
A	No cracks
C	Split top, cracked
E	Broken

Table A-6: Criteria for Defects – Misc.

Condition Rating	Corresponding Condition
A	No Defects, Loose hardware
C	Broken ground, Bent pole, Checking, Deformation, Base damage, Fire damage
E	Excessive surface wear, Major mechanical damage

Table A-7: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 30 years
C	31 to 40 years
D	41to 55 years
E	Over 55 years

Table A-8: Criteria for Out of Plumb

Condition Rating	Corresponding Condition
A	Inclination: 0 – 0.5 ft
B	Inclination: 1 – 1.5 ft
C	Inclination: 2 – 2.5 ft
D	Inclination: 3 – 3.5 ft
E	Excessive leaning, Inclination > 3.5 ft

Overhead (Pole Mount) Transformers & Distribution (Pad Mount) Transformers

Table A-9: Criteria for Transformer Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	Over 40 years

Ratio Banks

Table A-10: Criteria for Ratio Bank Age

Condition Rating	Corresponding Condition
A	0 to 7 years
B	8 to 15 years
C	16 to 23 years
D	24 to 30 years
E	Over 30 years

Power Transformers

Table A-11: Criteria for DGA Results

Gas Condition	Gas Generation Rate		
	Low	Low to High	High
Condition 1	A	A	B
Condition 2	B	B	C
Condition 3	C	C	D
Condition 4	D	D	E

Table A-12: Criteria for Load History

Condition Rating	Corresponding Condition
A	$LS \geq 3.5$
B	$2.5 \leq LS < 3.5$
C	$1.5 \leq LS < 2.5$
D	$0.5 \leq LS < 1.5$
E	$LS < 0.5$

Table A-13: Criteria for Insulation Power Factor

Condition Rating	Corresponding Condition
A	$PF_{MAX} < 0.5$
B	$0.5 \leq PF_{MAX} < 1$
C	$1 \leq PF_{MAX} < 1.5$
D	$1.5 \leq PF_{MAX} < 2$
E	$PF_{MAX} \geq 2$

Table A-14: Criteria for Oil Quality Tests

Test	Station Transformer Voltage Class	Grade
	U ≤ 69 kV	
Acid Number	≤0.05	A
	0.05-0.20	C
	≥0.20	E
IFT [mN/m]	≥30	A
	25-30	C
	≤25	E
Dielectric Strength [kV]	>23 (1mm gap) >40 (2 mm gap)	A
	≤40	E
Water Content [ppm]	<35	A
	≥35	E

Table A-15: Criteria for Service Age

Condition Rating	Corresponding Condition
A	Less than 20 years
B	20 to 40 years
C	40 to 60 years
D	More than 60 years
E	-

Table A-16: Criteria for Visual Inspection field (Bushing Condition/Overall Condition/Oil Leaks/Oil Levels)

Condition Rating	Visual Inspection (Ent)	Visual Inspection (Met)
A	No rust on tank/radiator, no damage to bushings, no sign of oil leaks, forced air cooling fully functional	Bushings are not broken and are free of chips, radial cracks, flashover burns, copper splash, and copper wash. Cementing and fasteners are secure.
B	Only one of the following defects: minor rust, or minor cracks in bushings or minor oil leak	Bushings are not broken, but minor chips and cracks are visible. Cementing and fasteners are secure.
C	Two or more of the above indicated defects present but do not impact safe operation	Bushings are not broken; however, major chips and some flashover burns and copper splash are visible. Cementing and fasteners are secure.
D	Tank/radiator badly rusted or major damage to bushing or major oil leak	Bushings are broken or cementing and fasteners are not secure.
E	Two or more of the above indicated defects or the cooling fans do not work	Bushings, cementing, or fasteners are broken/damaged beyond repair.

Table A-17: Criteria for Insulation Moisture Content

Condition Rating	Corresponding Condition
A	0 - 0.5% Moisture
B	0.5 – 1% Moisture
C	1 – 1.5% Moisture
D	1.5 – 2% Moisture
E	>2% Moisture

Circuit Breakers

Table A-18: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	All conditions marked as Satisfactory
C	One Not Satisfactory parameter
E	More than one Not Satisfactory parameter

Table A-19: Criteria for Contact Resistance

Condition Rating	Corresponding Condition
A	0-1%
B	1-3%
D	3-5%
E	>5%

Table A-20: Criteria for Timing/Travel Test

Condition Rating	Corresponding Condition
A	Close travel, wipe, over-travel, rebound, and time are all within specified limits. Trip time and velocity are within specified limits. Trip-free time is within specified limits. Interpole close and trip contact time spread is within the specified limits for the specific application.
B	Normal signs of wear with respect to the above characteristics.
C	One of the above indicated characteristics is unacceptable.
D	Two or more of the above indicated characteristics are unacceptable.
E	Two or more of the above characteristics are unacceptable and cannot be brought into acceptable condition.

Table A-21: SF6 Gas Analysis

Condition Rating	Corresponding Condition
A	No abnormal indications, as per IEC specification
B	High readings on moisture content, air, or CF_4
C	Probable indication of electrical activity (decomposition by-products)
D	Definite indications of electrical activity (decomposition by-products)
E	High levels of abnormal activity that cannot be brought into normal condition

Reclosers

Table A-22: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 7 years
B	8 to 15 years
C	16 to 24 years
D	25 to 32 years
E	Over 33 years

Protection Relays

Table A-23: Criteria for Service Age

Condition Rating	Corresponding Condition
A	In-service life to design life ratio of 0% to 20%
B	In-service life to design life ratio of 20% to 40%
C	In-service life to design life ratio of 40% to 80%
D	In-service life to design life ratio of 80% to 100%
E	In-service life to design life ratio of 100% or more

Table A-24: Visual Inspections

Condition Rating	Corresponding Condition
A	All components are clean; corrosion and leak-free and are in good condition. No external evidence of overheating, deterioration or abnormality or damage. No wear and tear noticeable.
B	Normal signs of wear with respect to the above characteristics.
C	One or two of the above characteristics are unacceptable.
D	More than two of the above characteristics are unacceptable.
E	More than two of the above characteristics are unacceptable and cannot be brought into an acceptable condition.

Battery Banks

Table A-25: Criteria for Service Age

Condition Rating	Corresponding Condition (years)
A	0-5
B	6-10
C	11-15
D	16-20
E	>20

Table A-26: Criteria for Testing

Condition Rating	Corresponding Condition
A	Battery capable of storing full rated energy
C	Battery stores marginally less than full rated energy, but still adequate for required functions
E	Battery stores significantly less than the full rated energy, inadequate for required functions

Table A-27: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	All conditions marked as Satisfactory
C	One Not Satisfactory parameter
E	More than one Not Satisfactory parameter

Grounding Grids

Table A-28: Criteria for Ground Grid Installation

Condition Rating	Corresponding Condition
A	Individual yards show considerable conductor redundancy (meshing), adjacent yards interconnected with multiple paths, conductors at a specified depth, sized for fault duty, with an adequate number of ground rods for winter conditions.
B	The installation has minor variations from originally specified or variation is only at isolated locations (1 or 2)
C	The installation has significant variation from original specifications or variation is noted at multiple locations
D	Installation major deviations from original spec or has been significantly damaged
E	Installation is damaged or degraded beyond repair.

Appendix B – METSCO Company Profile

METSCO Energy Solutions Inc. is a Canadian corporation which started its operations on the market in 2006. METSCO is engaged in the business of providing consulting and project management services to electricity generating, transmission, and distribution companies, major industrial and commercial users of electricity, as well as municipalities and constructors on lighting services, asset management, and construction audits. Our head office is located in Toronto, ON and our western office is located in Calgary, AB. Through our network of associates, we provide consulting services to power sector clients around the world. A small subset of our major clients is shown in the figure below.

Figure B-1: METSCO Clients

METSCO has been leading the industry in Asset Condition Assessment and Asset Management practices for over ten years. Our founders are the pioneers of the first HI methodology for power equipment in North America as well as the most robust risk-based analytics on the market today for high-voltage assets. METSCO has since completed hundreds of asset condition assessments, asset management plans, and asset management framework implementations. Our collective record of experience in these areas is the largest in the world, with ours being the only practice with widespread acceptance across regulatory jurisdictions. METSCO has worked with over 100 different utilities through its tenure, and as such, has been exposed and introduced to practices and unique challenges from a variety of entities, environments, and geographies. When a client chooses METSCO to work on improving Asset Management practices, it is choosing the industry-leading standard, rigorously tested and refined on a continued basis. Our experts have developed, supported, managed, led and sat on stand defending their own DSPs as utility staff giving METSCO the qualified expertise to provide its service to CNPI.

In addition to our work in the area of asset health assessments and lifecycle enhancement, our services span a broad common utility issue area, including planning and asset management, design, construction supervision, project management, commissioning, troubleshooting operating problems, investigating asset failures and providing training and technology transfer.

Our founders and leaders are pioneers in their respective fields. The fundamental electrical utility-grade engineering services we provide include:

- Power sector process engineering and improvement
- Fixed Asset Investment Planning – development of economic investment plans
- Regulatory Proceeding Support
- Power System Planning and Studies – identifying system constraints
- Smart Grid Development – from planning to implementation of leading technologies
- Asset Performance and Asset Management
- Distribution and Transmission System Design
- Mentoring, Training, and Technical Resource Development
- Health Index Validation and Development
- Business Case Development
- Owners Engineering Services
- Risk Modeling – Asset Lifecycle and Risk Assessment

DSP APPENDIX E:
CNPI AREA PLANNING STUDY (“APS”)

Area Planning Study - 2020:
Niagara (Fort Erie and Port Colborne)

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1 Introduction

1.1 Objective

This document is intended to provide a summary and analysis of the electrical distribution system at Fort Erie (FE) and Port Colborne (PC).

Areas requiring attentions in this system over a 10-year study period will be outlined. Once all existing areas of concern are identified, several alternatives will be presented to address the problems.

The alternatives will be evaluated to ensure that they satisfy all system requirements. A particular set of choices will be recommended.

1.2 Scope

This Area planning study examines the present system at FE and PC, and intends to anticipate any issues that may arise over the 10-year study period due to load changes and potential equipment failures.

This study is **NOT** intended to summarize system components and operations. System inventory of substations, distribution feeders, and voltage breakdown will be covered in other documents.

This study is also **NOT** generally intended to identify areas where deteriorated plant requires replacement, although asset condition will be taken into account in specific areas where design standards are not met for other reasons, such as system losses, overloads or contingency. Asset condition and plant deterioration is covered by a separate document – “CNPI Asset Management Program”.

1.3 Summary of Results

The Load Flow study indicates that the current system under peak load condition does not have a voltage drop issue at primary side, although it does indicate a few locations may have non-standard voltages at the secondary side.

Lines and distribution transformers generally do not have over-capacity issues if the summer maximum ratings (110%) were assumed when reviewing thermal overloads. However, considering factors such as imbalance, load coincidence, or system contingency, lines and transformers that are over 100% of its full capacity at system peak should be given attention and may entail further investigation on a case by case basis.

The technical demand loss at peak load for Port Colborne is about 3.72%, compared with 5.68% for Fort Erie. FE has higher system losses is mostly due to its 4.8kV Delta system, which has a loss rate as high as 7.05%. Unreasonable feeder configuration and long distances between load centers and sources are the major reasons for its relatively high losses.

The sensitivity analysis and contingency analysis illustrate that under moderate load growth forecast (30%) or under certain extreme contingencies (N-1 or less components in service), some sections display non-standard voltage due to load imbalance or long distance and some lines are over or close to their full capacity due to feeder configuration changes. In order to increase system reliability, further investigation is required for these sections.

Based on historical peak load between 2003 and 2019, a power curve-fit of the growth of the peak suggests a negative trend about -0.2%/year.

In summary, to correct present and predicted system deficiencies, the following work will be anticipated during the study period:

1. Retire Station12 (4.8kV Delta) and build a new 8.3kV substation (Oakes DS) at the same place where the location is in proximity to Fort Erie load center and optimal for providing back-up to Gilmore DS and Rosehill DS (2025).
2. Construct and Rebuild 8.3kV backbone feeders exiting the new 8.3kV Rosehill substation South of QEW (2021 – 2024).
3. Convert the non-backbone 4.8kV delta system south of QEW to 8.3kV Wye system, where the asset conditions and configurations meet the standards and technical requirements so that conversion becomes a more cost-effective option compared to rebuild (2021 – 2024).
4. Reinforce and upgrade the structure and equipment at Station19 to ensure its availability and reliability given that it will have limited backup from other substations due to distance and voltage drop.
5. Finish up the voltage conversion in Ridgeway area and supply the load from Station 19.
6. Install an 8.3kV-Wye to 4.8kV-delta rabbit bank on F1911 as a backup supply of 67RT3 for Point Abino loads.
7. Review all cases with non-standard voltage at peak load and prioritize them based on field-testing. Address the problem when an immediate adjustment is necessary (2016-2025).
8. Construct a new 8.3kV single-unit substation in order to ease-off the increasing load in Stevensville and address the long-time issues in this area such as voltage drop, small conductor size, phase imbalance, and unstable ratio bank reliability.
9. Convert the system of Stevensville from 2.4/4.16kV to 4.8/8.3kV utilizing the dual secondary voltages of existing rabbit banks. Eventually, the system will be

supplied from the new Stevensville substation and three legacy rabbit banks will provide the back-up.

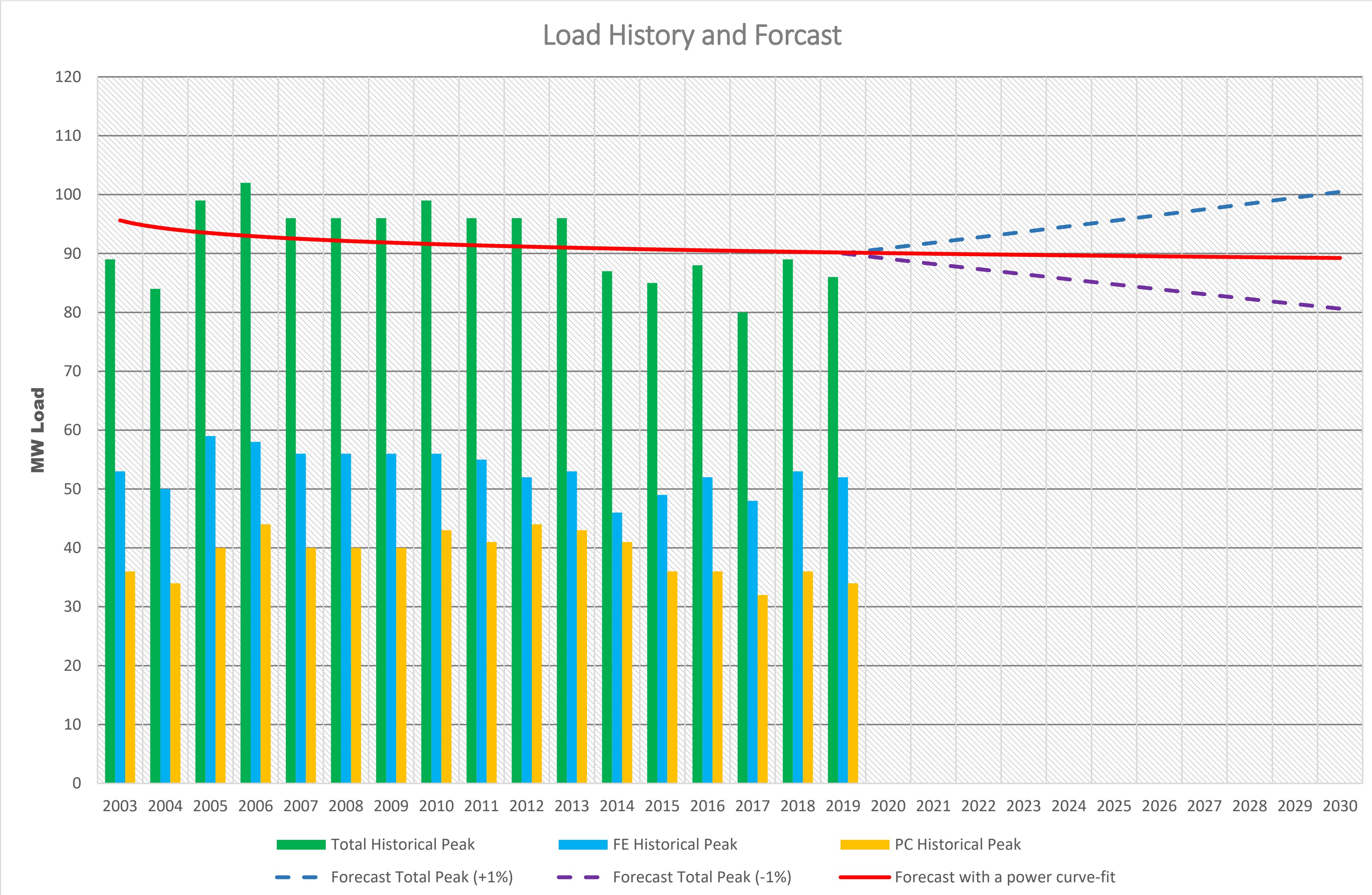
10. Review all cases with over-capacity transformers and prioritize them based on a statistical study with their year-round percentages of loading. This list will provide a reference that can work in conjunction with all projects that involve transformer replacement, repair, or relocate (2016-2025).
11. Retire Catharine Substation which is near the end of expected life and construct a new single-unit substation at the same place.
12. Review non-standard primary voltage and line thermal overload issues under a moderate load increase simulation. Given of the negative load forecast, these are not high-priority issues. However, measures such as correcting load imbalance, installing capacitor banks, or replacing with larger size of conductors should be incorporated into projects whenever it is possible (2016-2025).
13. Review non-standard primary voltage and line thermal overload issues under different contingency simulation. Adjust current contingency plans accordingly. If changing the plans is not practicable or efficient, lines over-capacity due to feeder configuration changes or voltage drop due to load imbalance should be corrected immediately (2016-2025) – Port Colborne small conductors.
14. Review the performance of Port Colborne DA and explore the feasibility to implement automation plan on other feeders to improve reliability.
15. Perform a feasibility study on the backup issue of Killaly DS.
16. Perform a feasibility study on building a new 8.3kV substation in Crystal Beach area, including location, technical design, contingency plans, and cost-benefit analysis, feeder configuration, and transition plan (2025).

2 Overview of System Load

Figure 1 contains a table and graph showing the historical peak at Fort Erie and Port Colborne since 2003. All these peak loadings are summer peak values (at July or August, with a few exceptions at September). According to historical records, peak loading at CNP (FE and PC) is nearly the same in the winter as in the summer, with the summer values usually being slightly larger.

Figure 1: Load History and Forecast (*Unit: MW)*

Year	Total Historical Peak	FE Historical Peak	PC Historical Peak	Forecast Total Peak (Power-curve fit)	Forecast Total Peak (+1%)	Forecast Total Peak (-1%)
2003	89	53	36			
2004	84	50	34			
2005	99	59	40			
2006	102	58	44			
2007	96	56	40			
2008	96	56	40			
2009	96	56	40			
2010	99	56	43			
2011	96	55	41			
2012	96	52	44			
2013	96	53	43			
2014	87	46	41			
2015	85	49	36			
2016	88	52	36			
2017	80	48	32			
2018	89	53	36			
2019	86	52	34	90.0	90.0	90.0
2020		57		90.3	90.9	89.1
2021				90.2	91.8	88.2
2022				90.1	92.7	87.3
2023				90.0	93.7	86.5
2024				89.9	94.6	85.6
2025				89.8	95.6	84.8
2026				89.7	96.5	83.9
2027				89.6	97.5	83.1
2028				89.5	98.5	82.3
2029				89.4	99.5	81.4
2030				89.4	100.5	80.6


Load History and Forcast
MW Load
120
110
100
90
80
70
60
50
40
30
20
10
0
2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030
Total Historical Peak
FE Historical Peak
PC Historical Peak
Forecast Total Peak (+1%)
Forecast Total Peak (-1%)
Forecast with a power curve-fit

A power curve-fit of the change of the peak values indicates a smoothed decline since 2003 and the forecasted peak of 2019 is 90MW. Using this forecasted peak as a baseline and assuming this trend will continue into the next ten years, at the end of the study period, CNP's peak load would be expected to reduce to 89.4MW. Figure 1 also contains an exponential curve-fit of forecasted loads at a lower (-1%) and a higher (+1%) anticipated growth rate.

Table 1 and **Table 2** show its corresponding coincident feeder and station transformer loading on June 10th, 2020 around 5pm (*a factor of 1.06 was applied*[1]), and this system snapshot is deemed as the most recent system peak moment in this study. The sum of the feeder peaks may be slightly different from the transformer bank due to the tiny difference of the time interval which is used to record the averaged coincident peak at that moment.

Table 3 gives a glimpse of the summer peak loading and energy consumption of CNP's 'interval metering' customers, which includes all those exceeding 500KVA in demand as well as a few smaller services where this metering was installed at customer request.

[1]: Reading from ST11 (FE) on June 10th 2020 at 5:00pm was 50.11MW. A factor of 1.06 was applied to all feeder and substation readings to simulate the true peak within the past 5 years.

Note: July 10th, 2020, peak load of FE was about 54MW.

Table 1: PC Feeder and Power Transformer Coincident Peak Load (June, 2020)

Feeder Name			Feeder MW	Transformer Bank MW
43M9			10.92	N/A
43M10			9.83	N/A
43M11			9.5	N/A
43M12			5.75	N/A
41M13			0.09	N/A
Killaly	West Bank	KF1	0.16	0.94
		KF2	0.71	
	East Bank	KF3	0.75	1.97
		KF4	1.27	
Jefferson		JF1	0.69	2.66
		JF2	0.74	
		JF3	1.29	
Beach	BF Bank1	SF1	0.49	2.98
		SF2	0.42	
		SF3	0.66	
		SF5	0.59	
	BF Bank2	N/A	N/A	0.02
Catharine		CF1	0.74	1.85
		CF2	0.16	
		CF3	0.62	
		CF4	0.46	
Fielden	Fielden Bank1	FF1	0.22	1.88
		FF2	0.28	
		FF3	0.7	
		FF4	0.6	
	Fielden Bank2	FF5	0.76	1.57
		FF6	0.38	
		FF7	0.59	

Table 2: FE Feeder and Power Transformer Coincident Peak Load (June, 2020)

Feeder Name			Feeder MW	Transformer Bank MW
Station 12	ST12 Bank1	F1265	0	0
		F1271	0	
		F1270	0	
	ST12 Bank2	F1266	0	6.44
		F1264	0.7	
		F1263	2.18	
		F1268	1.84	
		F1262	1.87	
	ST12 Bank3	F1267	0.73	2.81
		F1269	0	
		F1261	2.12	
		F1272	0	
Gilmore DS	GF Bank1	GF1	1.94	3.84
		GF2	1.96	
	GF Bank2	GF4	0	0.87
		GF5	0.88	
Station 17		17L5	1.48	19.63
		17L67	13.25	
		17L8	4.66	
		17L9	2.01	
Station 18	ST18 Bank1	18L5	3.29	16.1
		18L8	3.07	
		18L10	6.89	
		18L11	2.76	
	ST18 Bank2	18L4	4.56	17.7
		18L1	9.86	
		18L2	3.82	
Station 19	ST19 Bank1	F1911	1.63	5.45
		F1912	1.51	
		F1913	2.41	
	ST19 Bank2	F1921	1.86	6.14
		F1922	1.75	
		F1923	2.69	

Table 3: FE and PC Large Customer Load (July/August, 2018)

[Table of large customer loads removed for public filing]

[Table of large customer loads removed for public filing]

3 Methodology

3.1 Assumptions

The following assumptions provided the basis to conduct this study:

- As the normal supply of CNP, Hydro One Networks' 115kV transmission line will supply CNP's load. Under emergency conditions, CNP's load could be supplied from Buffalo, New York. This study does not apply to such an emergency situation.
- No significant changes to Hydro One's supply system, from the perspective of load supply, will occur during this study period. The new Port Colborne TS will be a replacement of the legacy TS.
- There will be no new large spot loads developing in the service territory and separate studies will be performed if necessary.

3.2 Study Procedure and method

After years of efforts, a detailed and comprehensive distribution system model had been established for CNP using the commercially available software WindMil/ArcMap from Milsoft Utility Solution and Esri. The modeling contains information of electrical connectivity, system voltage, winding connection of transformer, impedance, conductor size, pole assembly, and equipment definitions, which provided relatively accurate data to perform a system-wide electrical engineering analysis.

WindMil Engineering Analysis modules allow for a variety of analysis once the model is firmed up. In this study, the major functionalities that had been employed include Load Allocation, Voltage Drop, and Transformer Load. The energy consumption and kW demand data collected from CNP's billing system and Smart Meter system had been used to construct a valid load profile to serve the purpose of various analysis and simulations.

Please refer to WindMil's manual and related engineering documents for detailed algorithm and methodology.

3.3 Planning standards and performance criteria

The main standards and criteria that applied to in this study involved acceptable voltage range, overloading of conductors and transformers, and contingency reliability. Complete discussion on the standards, criteria, technical specifications, and procedures that will be used for CNP system planning is outlined in a separate internal document – “Standards for System Planning – Fortis Ontario”.

A few essential points had been summarized as follows:

- CSA CAN3-C235-83 (R2015) specifies the preferred voltage levels. Basically, under normal operating conditions, the voltage variation **at service entrance** is 110 to 125V (single phase, Line-to-Ground). Circuits above 1kV (**Primary**) should be maintained at any given point so as not to vary from nominal voltage by more than ±6% (i.e., 113 to 127V with 120V base).
- OEB Filing Requirements (2.8.9, 2020) requires an explanation of distribution losses greater than 5%. CNPI, with an overall energy loss less than 5%, is not on the agenda.
- All current-carrying components have ability to withstand thermal overloads to certain extent under different ambient conditions and load profile. The threshold percentage used in this study just represented a call for caution.

3.4 Limitations

The following limitations may affect the accuracy and authentication of the study:

- Due to data deficiency, some of the conductor size, equipment parameters and setup, and especially the location of the non-metered scattered loads are based on reasonable speculations.
- Peak Loads used in this study were retrieved at different time intervals (between 5 minutes to 1 hour), but they were deemed as coincident loads.
- System peak was not coincident with some large spot loads, and the simulations may not reflect the worst scenarios at a local level.
- Peak losses identified in this study may not reflect the real system losses and Load Factor and Loss Factor were estimated according to historical statistics and academic research.
- Feeder configuration at peak load only represented an approximation of the real system arrangement at that coincident moment when the load data was retrieved. A minor adjustment may be necessary in order to meet the convergence criterion of load allocation or voltage drop calculations.

4 Analysis and Results

4.1 Load Allocation

The most recent peak when performing this study, June 10th, 2020 at 5:00pm, was adjusted and deemed as system peak. System peaks in previous years may be higher than this recent peak, however, the feeder configuration could have changed and not match the current circuit model any more.

In this study, load had been categorized into three groups: Residential, KW Demand, and Others. Residential load values were retrieved from the hourly kWh recording of smart meters. KW Demand load values were obtained from interval meter readings which represent the five-minute-interval average of kW demand. All customers that do not have AMR data were using their monthly billing data. Most of these customers are small business. The total load values at different load control points were retrieved from SCADA. Since the input data were obtained with different methods and not necessarily coincident, this load allocation study was not simulating a fully real-time actual loading, but it did represent a close approximation of the system summer peak.

Table 4: Summary of System Load allocation

(Unit: MW)	Total LCP	Losses‡	Residential	Non-Residential	Allocated -R	Allocated -W	Allocated -B
Fort Erie	52.47	2.98	33.35	32.05	18.15	17.36	17.15
ST18	*33.59*	*1.54*	*18.12*	*15.47*	*11.28*	*11.6*	*10.71*
ST17	*18.88*	*1.09*	*15.23*	*3.65*	*6.38*	*6.06*	*6.44*
Port Colborne	34.68	1.29	17.83	16.85	11.7	11.81	11.17

‡: Total losses incorporate transmission lines and station power transformers.

Table 4 demonstrates the summary results of load allocation. There is a separate part for 41M13 which is supplied by Crowland TS. Since it only has 0.23MW load, the result is not included in the table.

Detailed analysis on load density distribution, system losses, thermal overloads, and load balance are as follows.

4.1.1 Load Density distribution

Figure 2 displays the load density distribution across Fort Erie and Port Colborne. Each pixel represents the total peak load within a 200m x 200m area. This map clearly identified the areas with high load density, which are denoted as “load centers”.

According to this map, the distribution of current substations is fairly reasonable in Port Colborne in terms of their locations. However, for Fort Erie downtown and its surrounding areas, Gilmore substation is slightly strayed away from the load centers and Station 12 is close to its north part of load center, but to some extent, far away from its south part of load center – Crescent Park. Obviously, improvement of substation locations and feeder configuration should be one of the considerations when planning any project in this area.

Bear in mind that location of a substation relative to its load center only represents one of the contingencies when locating or relocating substations and there are usually many other limitations and considerations during this process.

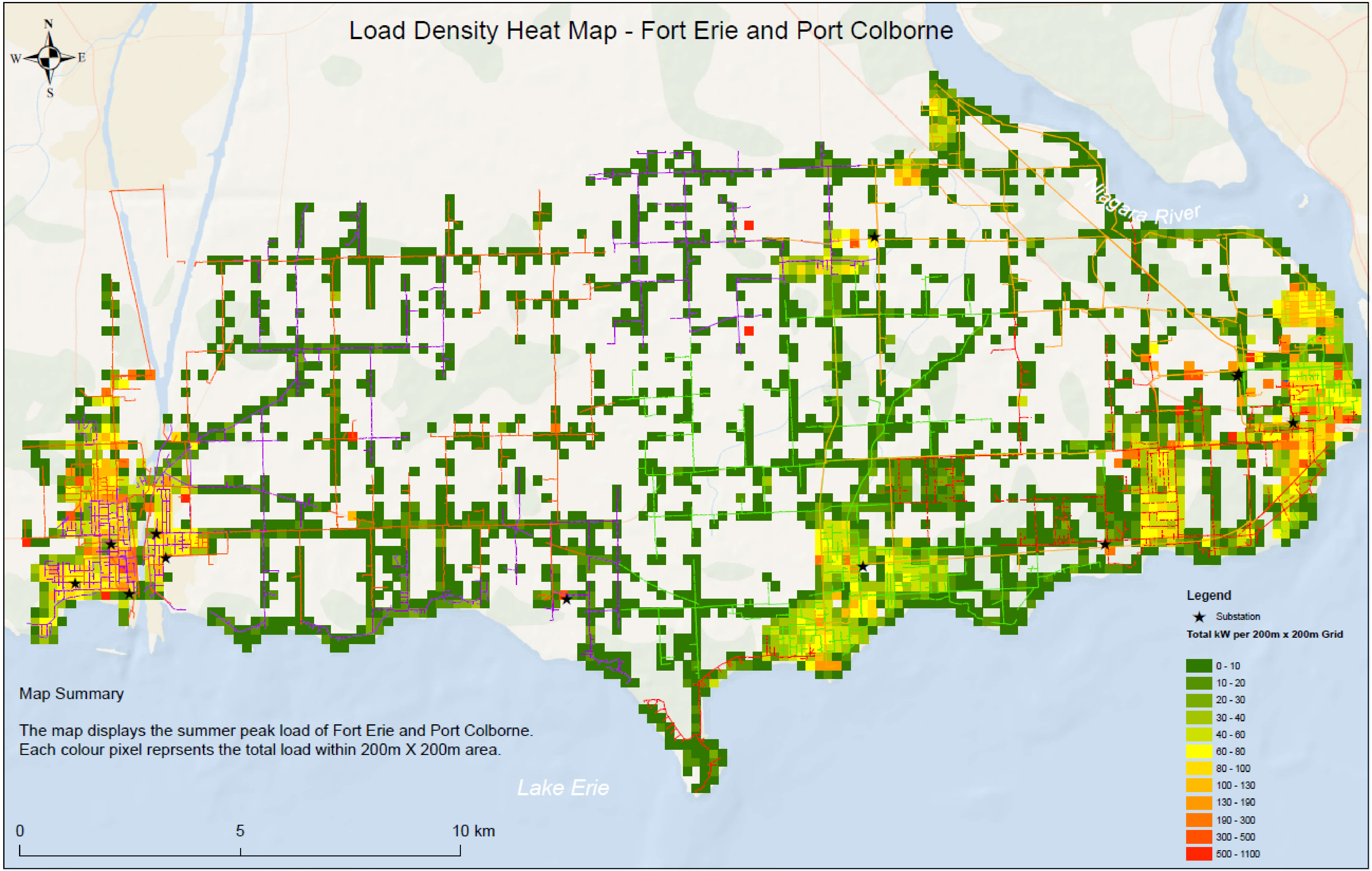


Figure 2: Fort Erie and Port Colborne Load Density Map

4.1.2 System Technical Losses

Load allocation analysis shows the technical demand loss at peak load for Port Colborne is about 3.72%, compared with 5.68% for Fort Erie. The reason that FE has higher system losses is mostly due to its 4.8kV Delta system (Station 12 and ratio banks), which has a loss rate as high as 6.53%. The remaining Wye system of Fort Erie thus has a 4.4% peak loss rate. Overall, FE demand loss has been reduced from 6.04% (2016) to 5.68% with the progressing of QEW North conversion.

Table 5 shows Fort Erie and Port Colborne energy losses between 2014 and 2019. In order to link the energy loss to the peak loss calculated from the load allocation analysis, a simplified formulae,

$$E\% = (0.7*\text{Load Factor} + 0.3) * D\%$$

was used in this study, in which, E% represents the average energy loss and D% represents the demand peak loss (technical losses only). This formulae is derived from the relationship between a typical distribution feeder demand loss and the load factor[2].

[2]: Refer to "Transmission and Distribution Electrical Engineering", C. Bayliss and B. Hardy, 2012.

Table 5: Fort Erie and Port Colborne Energy Losses 2014-2019[3]

	2019					2018	2017	2016	2015	2014
	YTD Peak Billing Demand (MW)	YTD MWh's Purchased	YTD MWh's Sold	YTD MWh Losses	YTD % Losses	YTD % Losses	YTD % Losses	YTD % Losses	YTD % Losses	YTD % Losses
Fort Erie	52.2	-	-	-	-	-	-	5.1%	4.6%	4.4%
Port Colborne	34.3	-	-	-	-	-	-	4.8%	4.2%	3.9%
Niagara	86.5	431,292.3	412434.7	18857.6	4.37%	4.57%	4.83%	-	-	-

[3]: Combined FE/PC as Niagara Totals for 2017 Onwards

Assuming the load factor is 0.55 across the system, the calculated Fort Erie energy loss based on the 5.68% peak demand loss will be 3.89%, while the calculated Port Colborne energy loss based on the 3.72% peak demand loss will be 2.55%. Compared with Table 4, the real energy loss 2019 was 4.37% (combined FE/PC). This number is supposed to be higher than the calculated energy loss because it is generally accepted that an allowance in the range 0.2% to 1.0% is appropriated to accommodate meter inaccuracy and theft (non-technical losses). Port Colborne's calculated energy loss is lower than expected, which implies that Port Colborne may have larger Load Factor than Fort Erie and the real energy loss for Port Colborne was once as low as 3.3% in 2012.

In summary, Port Colborne has lower system losses than Fort Erie. FE has higher system losses is mostly due to its 4.8kV Delta system. Unreasonable feeder configuration, long distances between load centers and sources, small conductor size with relatively higher resistance are the major reasons for the high losses of current Delta system.

4.1.3 Thermal Overloads

Various current-carrying components of the distribution system are subject to thermal overloads in different ways. This study was mainly focusing on transformers and conductors.

Conditions must be taken into account when determining if a transformer is overloaded. Since this study was only simulating summer peak, the results have to be combined with a further investigation on the year-round transformer load profile.

Basically, according to related standards and manufacturer's specification, transformers can be safely overloaded 100% under hot and continuous loading and up to 140% under 4-hour overload. Overhead conductors may be overloaded up to 125% of ampacity as long as the ambient temperature remains below 0°C.

Although transformers and conductors all have over-capacity capability, in this study, transformers and conductors that were overloaded to 110% and 100% separately of its nominal capacity were marked up for further investigation. This will facilitate us to take proactive measures should these transformers or conductors have been with unreasonable ratings.

Figure 3 shows the locations of transformers that exhibit over-capacity in the simulation and need further investigation on their potential of being over-loaded. In total, 79 distribution transformers were 110% (or greater) overloaded. No primary conductors were 100% overloaded, but 0.4km secondary conductors were

100% (or greater) overloaded in the peak loading simulation. Most of these secondary overloaded conductors were associated with the overloaded transformers and require a further investigation.

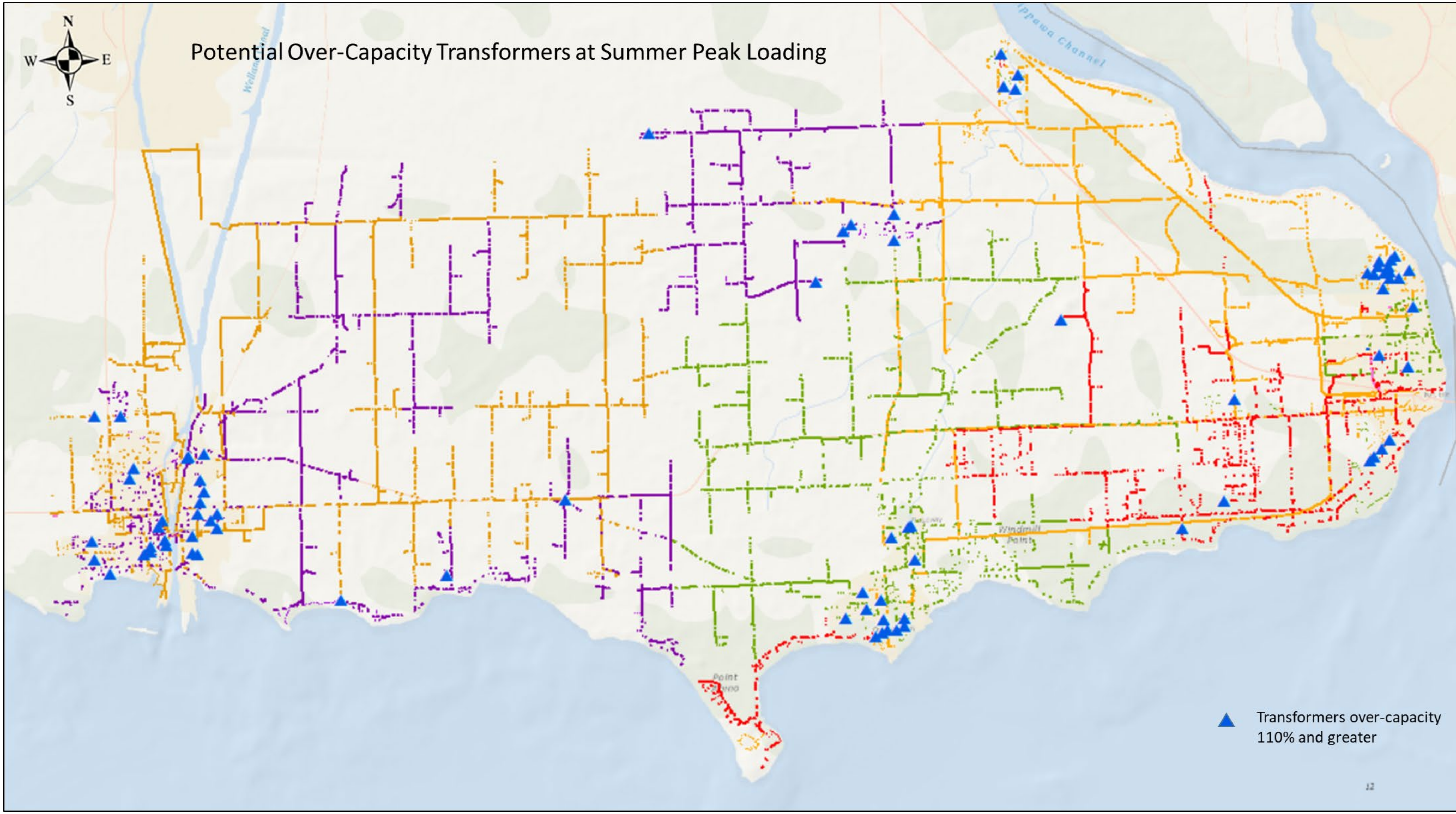


Figure 3: Potential Over-Capacity Transformer at Summer Peak Loading

4.1.4 Load Imbalance

Table 4 shows that at system level, the loads on different phases are well balanced and the imbalance for both Fort Erie and Port Colborne is within 10%.

At substation level, this study did not suggest any significant imbalance issue. Since the feeder configuration and power transformer capacity specification have already considered the factor of imbalance, especially under contingency situations, as long as the imbalance is within a threshold, imbalance should not be of any concern at this level.

At Ratio Bank level, this study did bring some concerns on load imbalance at 9RT1 and 8RT1. Under normal, or even peak-load condition, the imbalance is within the tolerance and won't cause voltage drop or over-capacity issues. However, under certain contingency situations or when the load grows significantly, the load imbalance will have the potential to cause problems. The sections of Sensitivity Analysis and Contingency analysis will have further discussion on the findings.

4.2 Non-standard Voltage

This study shows No Voltage drop issue at primary circuit (**Figure 5**), while a few spots at secondary side seem having non-standard voltage (**Figure 4**), assuming 110-Volt or below on a 120-Volt base will be deemed as non-standard (Refer to Section 3.3).

A further field check should be conducted on these locations with secondary voltage issues. If confirmed, the problem can be addressed locally by either tapping-up the corresponding distribution transformer or adjusting the downstream load.

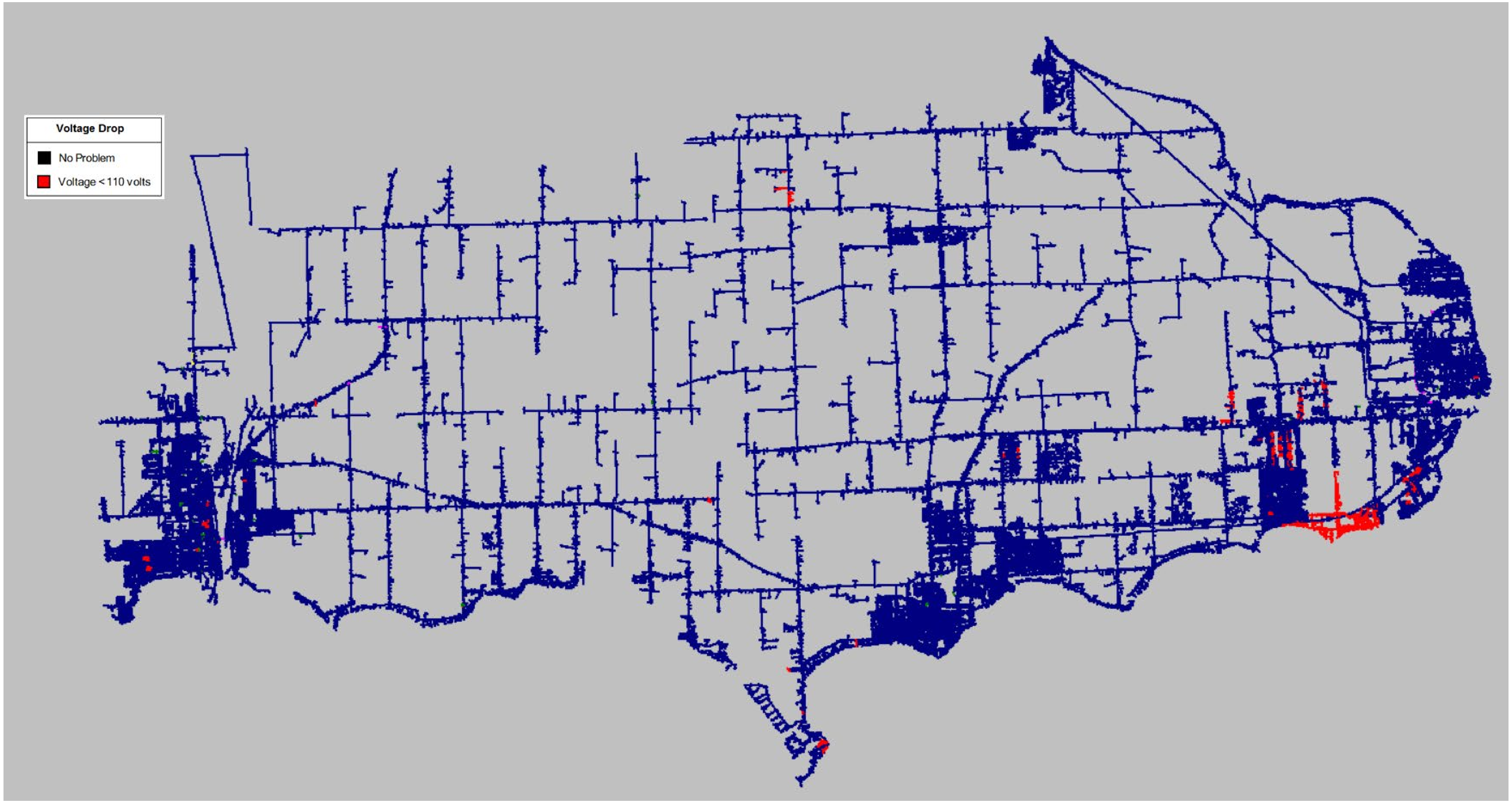


Figure 4: Peak Load - Voltage Drop Map (with Secondary)

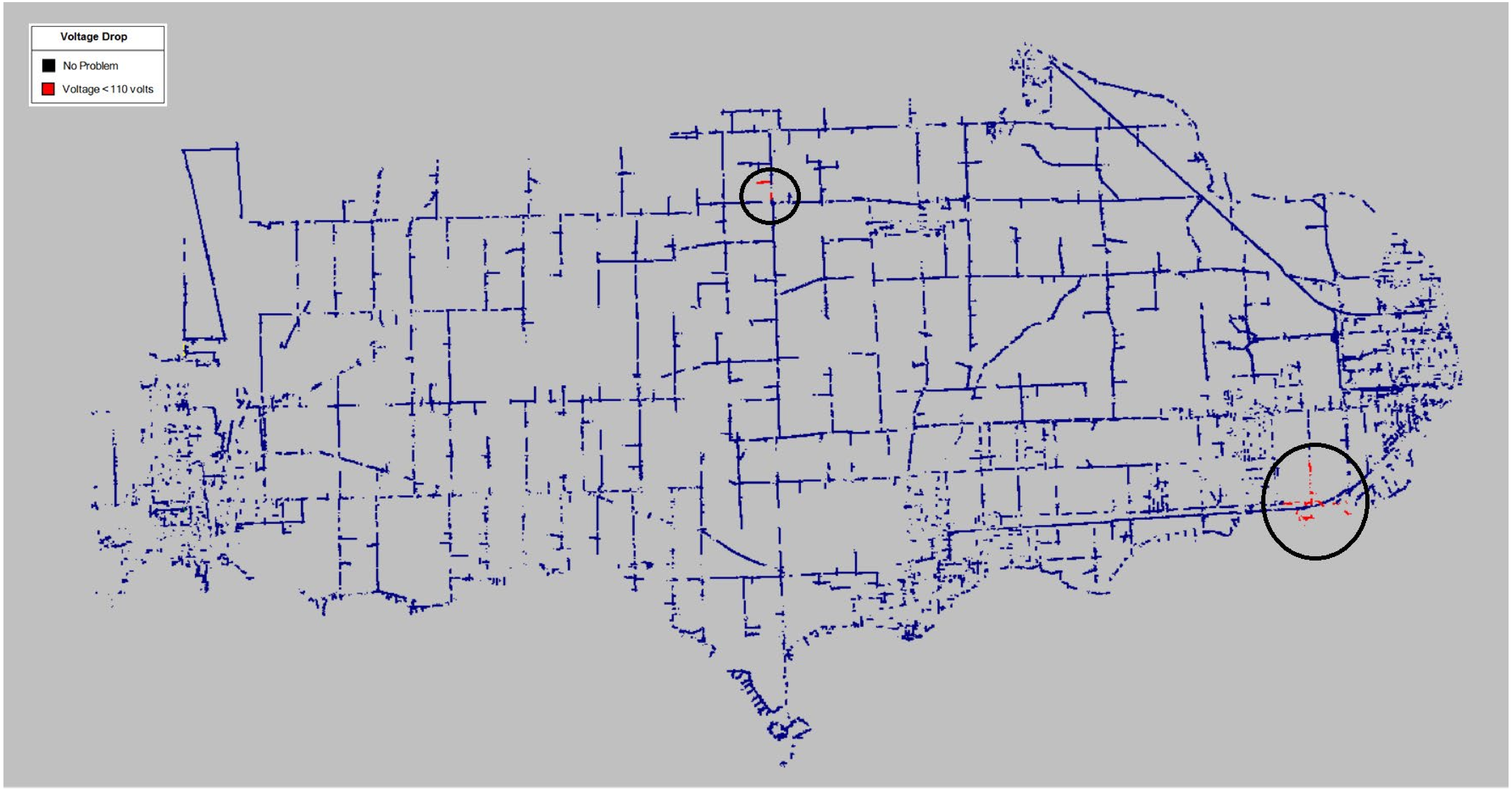


Figure 5: Peak Load - Voltage Drop Map (Primary Only)

4.3 Sensitivity Analysis

Although the load forecast indicates a negative load growth driven by both the demand decrease and the CDM program, a sensitivity analysis with an increased peak load by 30% was still performed to test the robustness of the system in dealing with extreme loading condition.

Figure 6 shows that when the overall load increases about 30%, the system will encounter voltage drop issues not only at the secondary side, but at the primary side as well. Three locations were identified as having the potential of primary voltage drop and they are all located in Fort Erie:

- A section of downstream of 9RT1 (Ratio Banks – 2.4/4.16kV)
- A section of downstream of 8RT1 (Ratio Banks – 2.4/4.16kV)
- A section of downstream of F1261 (Station 12 Feeder – 4.8kV Delta)

Voltage drop on 9RT1 is only on C (Blue) phase. Currently, the load on 9RT1 is not significant, but nearly 60% of the load is on C phase. When the load level increases 30%, the long distance causes the voltage drop on C phase close to the far end of the reach of 9RT1.

Voltage drop on 8RT1 is on A (Red) phase only. The reason is similar to 9RT1; however, the load imbalance is much worse than 9RT1. Currently, over 90% of the load is on Red phase. In addition, since the load level downstream of 8RT1 is much larger, increased load (roughly to 1MW) will not only cause voltage drop, but also result in the potential over-capacity on the 3/0 Aluminum conductors currently installed downstream of 8RT1.

Voltage drop on F1261 is due to the long distance away from substation. Currently, Regulator 3298 is installed in the field to mitigate the voltage drop on this feeder. With increased load, the feeder cannot maintain standard voltage level on a section ahead of Regulator 3298.

Potential voltage drop issues on 9RT1 and 8RT1 can be addressed by tapping-up the transformer or re-allocating the load more balanced among phases. Potential voltage drop on F1261 can be addressed by re-locating the regulator or installing extra capacitor banks.

Bear in mind that the system only presents these issues when assuming significant load increase, therefore, there is no intention of seeking immediate solutions or putting these issues in priority for the current time being.

Figure 6: Load Growth 30% - Voltage Drop Map (Primary Only)

4.4 Contingency Analysis

This section examines if the system can still meet its design requirements assuming one of the components fails (i.e. N-1 components in service).

For general discussion on Fort Erie and Port Colborne contingency capability in terms of Supply, Power Transformer, Ratio Banks, and Distribution, Please refer to previous CNPI Area Planning Studies. A few updates since last study has been highlighted as follows:

- With the newly constructed International Power Line (IPL), the simultaneous loss of the New York and Hydro One Grids should be considered unlikely event.
- With the newly installed bypass switch adjacent to ST17 and the backup from IPL, the simultaneous loss of ST17 and ST18 should be considered unlikely event.
- With the recent fix on a section of burned underground cable due to fault and aging, the two transformers of Killaly DS are now supplied by two separate overhead taps with separate risers entering the substation. This will minimize the risk of losing the whole supply from Killaly DS.
- With the newly installed and replaced power transformers, Fielden DS is now a dual-transformer substation with both transformers less six-year-old. With a number of switching operations, Fielden DS not only has the ability to handle a single contingency event, but also has sufficient transfer capability to back up its neighboring DS provided that the connecting conductors have the adequate ampacity to deal with the load transfer.
- With the newly constructed dual-element Gilmore DS, the risk of losing both transformers should be considered unlikely event.
- With the newly constructed Jefferson DS, the risk of losing the whole supply of Jefferson feeders has been minimized.

This study performed several contingency analysis based on simulations of scenarios outlined in the subsequent case studies.

4.4.1 Case Study - Failure of Station 17

This case assumes the sole transformer of ST17 fails and its downstream loads are picked up by Station 18 feeders.

Table 6 shows the feeder loading result of one of the contingency plans in case of ST17 failure. ST18, with two 37.5/60/67.5 MVA transformers) seems adequate to supply the entire Fort Erie system (with 18L11 disconnected) and there are no incurred non-standard voltage issues due to this contingency.

Generally, the present 34.5kV feeder configuration would allow the backup between ST17 and ST18 without causing any over-capacity or non-standard voltage issues.

Table 6: Feeder Loading – Case 4.4.1

Element Name	Thru Kw	Thru Amps	Thru Amps A	Thru Amps B	Thru Amps C
RC18L11	0	0	0	0	0
RC18L2	3414.185	56.034	54.424	65.05	48.627
RC18L5	3702.861	60.975	55.724	69.659	57.542
RC18L4	5198.323	83.125	78.123	76.245	95.008
RC18L10	8955.325	145.26	151.091	152.289	132.4
RC18L1	12178.943	201.852	207.956	203.437	194.165
RC18L8	14517.004	236.429	278.461	184.347	246.479

4.4.2 Case Study - Failure of Station 17 and Feeder 18L8

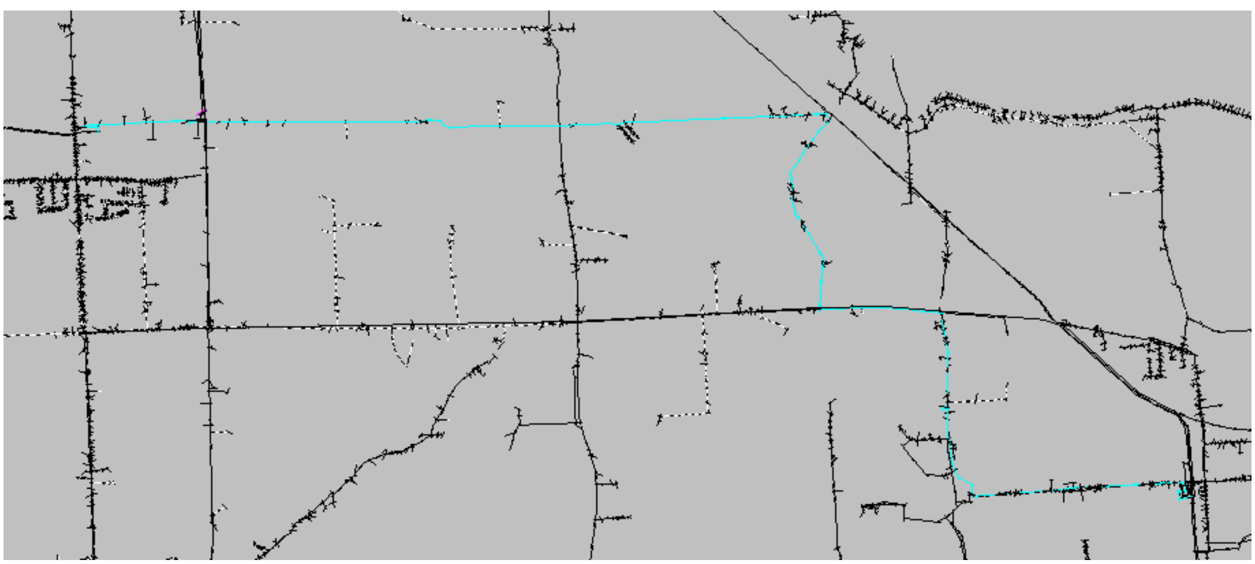
This case assumes the sole transformer of ST17 and the feeder with heaviest load of ST18 (18L8) fail simultaneously.

Table 7 shows the feeder loading result of one of the contingency plans in case of both ST17 and 18L8 failures. ST18 feeders still has sufficient capacity to pick up the entire load of Fort Erie. However, the analysis also suggests that a section of downstream of 8RT1 displays the issues of non-standard primary voltage on one of the phases. A section near Bowen Rd. & Sunset Dr. may be over-loaded as well.

Table 7: Feeder Loading – Case 4.4.2

Element Name	Thru Kw	Thru Amps	Thru Amps A	Thru Amps B	Thru Amps C
RC18L11	0	0	0	0	0
RC18L8	0	0	0	0	0
RC18L5	3707.025	60.268	55.082	68.786	56.936
RC18L2	5477.699	89.772	77.117	96.333	95.864
RC18L10	8949.693	143.334	148.682	150.698	130.622
RC18L1	12171.091	204.85	211.373	206.449	196.729
RC18L4	17858.367	294.988	346.698	234.089	304.178

Compared with the scenario 4.4.1, ratio bank 8RT1 is further away from the supply source in this scenario. **Figure 7** compared the distance under these two scenarios (supply path was highlighted with blue color). Obviously, when 18L8 fails, the configuration change could cause the further voltage drop near the end or the over-capacity of the connecting conductors. This study suggests that current contingency plans should be reviewed and adjusted to avoid non-standard voltage. Conductors that have the potential to become "connectors" need to be upgraded to at least 336 ASC.



(Case 4.4.2)

(Case 4.4.1)

Figure 7: Distance between 8RT1 and Supply Source – Case 4.4.1 vs. Case 4.4.2

4.4.3 Case Study - Failure of Gilmore TB1

This case assumes one of the transformers in Gilmore DS fails and its downstream loads are picked up by the other Gilmore transformer. Bearing in mind that the progressing Fort Erie conversion project has created two isolated “islands” in terms of operating voltages. Gilmore DS supplies a 4.8/8.3kV Grounded-wye system and ST12 supplies a 4.8kV Delta system. Both substations will have no backup sources (other than backups between their own transformers) until the conversion is completed.

Table 8 is the feeder loading of one of the contingency plans under this scenario. Even as the conversion of QEW North proceeds, both transformers of Gilmore DS are 7.5/10 MVA and supposed to have sufficient capacity to carry the entire load in the event of one transformer failure.

In the demonstrated contingency plan, a few feeders may pick up more loads than other feeders and some feeders display phase imbalance issues. However, these problems can be fixed by adjusting the contingency plan and more carefully spreading the loads within feeders. Generally, the dual-element design of Gilmore would allow for the backup of two transformers without causing any over-capacity or non-standard voltage issues.

Table 8: Feeder Loading – Case 4.4.3

Element Name	Thru Kw	Thru Amps	Thru Amps A	Thru Amps B	Thru Amps C
GF5	650.434	45.415	29.796	54.961	51.487
GF4	0.327	0.022	0.067	0	0
GF1	1590.796	112.567	133.006	113.482	91.214
GF2	2365.447	167.702	258.779	118.938	125.389

4.4.4 Case Study - Failure of Station 12 TB2

This case assumes the transformer with the largest capacity on ST12 (ST12-TB2) fails. With current configuration, Station 12 will have no backup from other sources because of its special operating voltage and delta configuration. As a result, it is critical to examine the situation of the worst scenario, in which, the 10MVA transformer of ST12 fails.

Table 9 shows the feeder loading result under this scenario. To be noted, this simulation already contained some load transfer among feeders. A better contingency plan is possible but may require the upgrade of tie switch or conductor size in the field. In general, there is no primary voltage drop or over-capacity issues under this scenario if following a well-prepared contingency plan.

Table 9: Feeder Loading – Case 4.4.4

Element Name	Thru Kw	Thru Amps	Thru Amps A	Thru Amps B	Thru Amps C
F1272	2.103	0.242	0.242	0.242	0.241
F1269	295.158	35.681	31.372	46.363	29.307
F1267	931.563	111.993	84.461	116.22	135.298
F1271	1314.818	159.226	150.925	156.248	170.504
F1264	1409.984	169.109	165.888	196.465	144.973
F1268	1571.688	188.157	184.565	158.937	220.97
F1270	2352.546	286.493	261.277	327.554	270.647
F1265	2368.498	290.1	215.826	346.702	307.771
F1261	3591.571	430.983	456.818	447.677	388.453

The two 5.1/6.75 MVA transformers in ST12 have been in service for a long time. If the 10MVA TB2 fails, near 1/3 of Fort Erie loads, mostly distributed in the downtown area, will have to count on these two aging transformers, resulting in increased risk of power outages. In order to improve system reliability under this scenario, this study suggests:

- Create at least two contingency plans under this scenario, field-check the operating condition of the tie switches and the size of the connecting conductors in these plans, and make sure they are prepared for load transfer.
- Find at least two strategic locations to install the 1.5MVA (3*500KVA) ratio banks so they are prepared to ease the voltage drop issue during summer under N-1 contingency and ready to pick up loads under N-2 contingency scenario, considering the special isolated condition of ST12 within the next few years.
- Large loads that have 34.5kV nearby should be transferred using ratio banks. This will relieve the burden on ST12 and minimize the risk of coincident system peak and large load peak. If considering the imbalance of load allocation between these two transformers, one of the transformers can be easily overloaded to over 140% of its nameplate rating.

4.4.5 Case Study - Failure of Station 19 TB1 after Ridgeway Conversion

This case assumes one of the two 10/13.3MVA transformers on ST19 (TB1) fails. As CNP's newest station, ST19 has a steadily increasing load as 4.8Δ-to-8.3Y voltage conversion programs are completed. So far, most of the load is on TB2 and TB1 only has one feeder with a non-significant load in service. As a result, the discussion of this contingency is more meaningful when the conversion is done. This study simulated the situation when all the Ridgeway Ratio Banks (*10RT5, 10RT3, 10RT4, 9RT2, and 67RT3*) had been converted to 8.3Y and connected to ST19 feeders, and at the same time, ST19 TB1 failed.

Table 10 shows the feeder loading result of one of the contingency plans under above scenario. Generally, either transformer on Station 19 is able to carry the entire load, even after the whole Ridgeway conversion is finished and supplied by Station 19. No non-standard voltage or over-capacity issues have been identified in this simulation.

Table 10: Feeder Loading – Case 4.4.5

Element Name	Thru Kw	Thru Amps	Thru Amps A	Thru Amps B	Thru Amps C
F1921	3704.376	254.115	232.425	239.924	289.997
F1922	3178.031	217.674	200.108	267.149	185.765
F1923	4075.178	278.842	322.126	219.586	294.813

4.4.6 Case Study - Failures of Jefferson and Catharine Simultaneously

So far, all the contingency analysis is targeting at Fort Erie given that the efforts for its 4.8kV Delta system conversion will absorb the majority of capital expenditures for the next few years.

For Port Colborne, the major issue is to deal with the aging condition of Jefferson DS and Catharine DS. Both these two substations are single-transformer DS and have only one 27.6kV supply cable and one bus supplying the 4.16Kv feeders. With the newly installed 6.5/8.67MVA transformer on Fielden DS (TB2), the system now has the potential to pick up the entire load with Fielden TB2 in the event of failures of both Jefferson DS and Catharine DS. This case assumes such a scenario.

Table 11 shows the feeder loading of Fielden DS under this contingency. Obviously, FF6 and FF7 are close-to or over their capacity. FF5 is on TB2, however, there is no feeder exit for it yet. After examining the current feeder configuration, it seems not too much load can be conveniently transferred between TB2 feeders and TB1 feeders. Large load transfer between TB1 and TB2 calls for the installation of new tie switches or the build of new sections of connecting lines.

Figure 8 illustrated that abundant sections of primary lines used to be supplied by Jefferson or Catharine presented non-standard voltage or encountered over-capacity issues once they were supplied by Fielden TB2 based on current feeder configuration.

Table 11: Feeder Loading – Case 4.4.6

Element Name	Thru Kw	Thru Amps	Thru Amps A	Thru Amps B	Thru Amps C
FIELDEN D.S. 1	521.036	72.596	109.859	69.884	38.046
FIELDEN D.S. 2	1117.469	157.04	277.903	164.488	28.729
FIELDEN D.S. 3	636.82	88.54	93.413	65.748	106.46
FIELDEN D.S. 4	635.581	90.031	117.884	84.437	67.772
FIELDEN D.S. 5	0	0	0	0	0
FIELDEN D.S. 6	3266.269	486.897	477.83	374.826	608.035
FIELDEN D.S. 7	2834.068	427.935	511.946	337.419	434.44

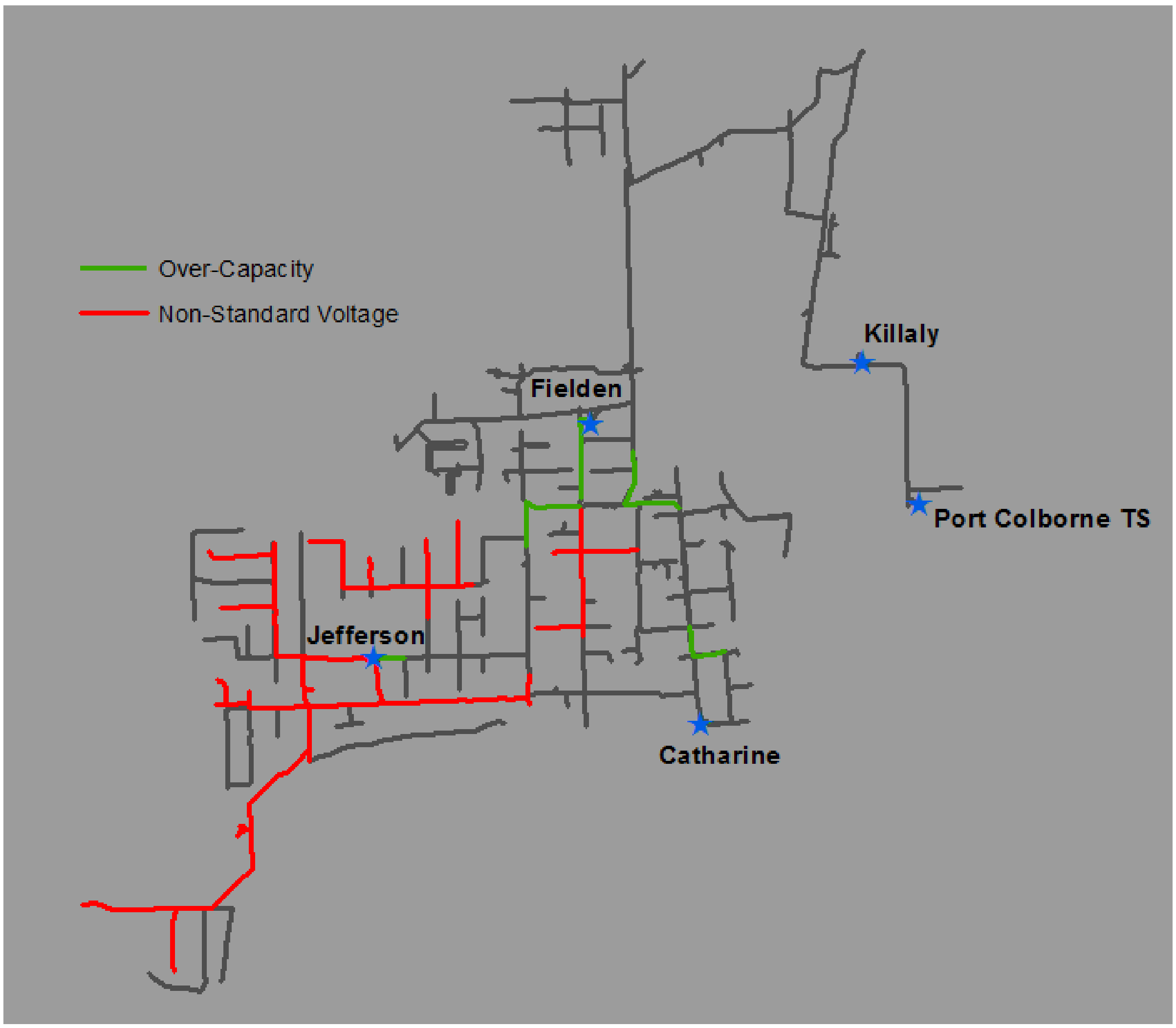


Figure 8: Non-standard Voltage and Over-Capacity Issues – Case 4.4.6

In summary, both Jefferson DS and Catharine DS have no sufficient transfer capacity on their neighboring DS's, due to small connecting conductors or long distance, to accept peak loads and still maintain standard voltages in the event of a substation failure. If the plan is to use Fielden TB2 to back up Jefferson and/or Catharine, the whole system in this area requires an overhaul to reinforce the conductor size, tie switch, and feeder re-configuration.

4.4.7 Case Study – Failure of Killaly East Bank

This case assumes the east 3.75/5 MVA transformer in Killaly DS fails and the load is picked up by the west 3.75/5 MVA transformer. Since today's peak load of Killaly is close to 3MW, both transformers of Killaly are supposed to have sufficient capacity to carry the entire load in the event of one transformer failure. The load of the feeders on the failed transformer can be picked up either by closing the tie-bus switch in the substation or by switching from the line side. **Table 12** shows the feeder loading of one of the contingency plans under above scenario. Generally, no non-standard voltage or over-capacity issues have been identified in this simulation.

Table 12: Feeder Loading – Case 4.4.7

Element Name	Thru Kw	Thru Amps	Thru Amps A	Thru Amps B	Thru Amps C
KFD-1	150.904	21.292	30.137	10.438	23.3
KFD-2	662.644	93.133	58.309	106.72	114.369
KFD-3	738.752	104.71	98.76	109.398	105.971
KFD-4	1176.174	165.858	229.859	161.125	106.59

4.4.8 Case Study – Failure of Stevensville Ratio Bank 9RT1

This case assumes one of the Stevensville ratio bank 9RT1 fails and the load is picked up by the other two ratio banks, 8RT1 and 8RT2. Due to the limitation of existing configuration, 8RT2 is reaching its maximum capacity with a significant loading on A phase (**Table 13**). Stevensville area has extensive primary truck lines with small conductor size, including 1/0 ACSR and #2 CU. It also suffers from unbalanced phases. Under this contingency, the non-standard voltage shows up in a wider range than it normally does (**Figure 9**), which calls for attention to solutions to address the challenges facing Stevensville.

Table 13: Feeder Loading – Case 4.4.8

Element Name	Thru Kw	Thru Amps	Thru Amps A	Thru Amps B	Thru Amps C
9RT1	0	0	0	0	0
8RT1	808.655	115.224	71.201	83.275	191.196
8RT2	1419.393	202.33	242.888	190.412	173.69

Figure 9: Non-standard Voltage and Over-Capacity Issues – Case 4.4.8

4.4.9 Case Study – Failure of Crystal Beach Ratio Bank 67RT3

This case assumes the 1.5 MVA ratio bank fails. As the Ridgeway conversion is close to being completed, the service territory of 67RT3 becomes an island that still operates with the 4.8kV delta. There are no backup sources nearby and the customers may have to experience a prolonged outage. On the other hand, the unique geographical location of the Point Abino area poses a challenge to the voltage conversion. There is an immediate need for CNPI to seek an alternative source to provide backup.

5 Alternative Analysis and Solutions

This study disclosed some potential issues of the current system and most of them are minor and subject to further investigation and field check. Among these issues, the relatively high risk of phase imbalance, voltage drop, and reliability issue in Stevensville, the back-up and load increase issue in Station 19 service territory, and the challenges and risks facing us during and after QEW South voltage conversion are of our most concerns. In order to address these issues, alternative analysis has been performed to compare different options. Although saving losses is one of the major drives, safety, asset aging, and cost are also critical considerations when determining the best option.

5.1 QEW-South Conversion and Station 12 Decommissioning

According to DSP 2016, CNPI plans to convert the legacy 4.8kV Delta system in Fort Erie downtown area into a 4.8/8.3kV wye system. Refer to DSP 2016 for detailed justification. The major points are highlighted as follows:

- Much of the CNPI legacy 4.8 Delta system is nearing end-of-life, and will require investments in asset renewal, especially the substation equipment, poles, and aerial cables.
- 4.8kV delta system is rare and unsafe.
- 8.3Wye is the logical and economical successor to the 4.8 Delta given of the similar clearance requirements and savings on components already rated at 15kV.
- CNPI can create substantial annual long term reductions in distribution operating losses by introducing a higher voltage system.

Historically, the loads of Fort Erie Delta system were distributed at the north of highway QEW (QEW-North) and the south of QEW (QEW-South). QEW-North conversion is expected to be fully completed by the end of 2020. The combined load to be converted at QEW-North is about 7.5MW (including the loads being converted onto 19.9/34.5kV feeders); the combined load to be converted at QEW-South, including loads on the four remaining Station 12 feeders and the two ratio banks (10RT3, 10RT1), is about 9.1MW. In order to facilitate the QEW-South conversion, DSP 2016 recognized the necessity for the construction of a new DS should a plot of land in a suitable location be acquired.

On the original 2016-version of DSP, it stated that the acquisition could take place sooner than 2020 if the right opportunity arises to purchase a suitable parcel of land in an attractive location. After a few years' seeking for a suitable land, in 2019, a lot for sale near the intersection of Rose Hill Rd and Dominion Rd attracted the attention. Based on a detailed load flow and system configuration study, this location fits well into the strategic plan of QEW South conversion and a decision had thus been made to acquire this land and construct the new Rosehill DS. By 2020, after completion of other related material projects in this DSP 2016, CNPI anticipates that its Fort Erie distribution system should be as shown in **Figure 10**.

There will be a large ‘residual’ area on the south side of the QEW area served by Station 12 DS at 4.8kV (delta). Some of the load in this area may be suitable for conversion to 34.5kV, but the majority will have to be converted to 8.3kV (wye) due to spacing constraints with the legacy distribution lines and availability of 34.5kV distribution lines. Since the conversion of QEW North is ahead of the schedule, the effort to convert the South area is now planned to begin by the end of 2020.

The geographical location of RoseHill DS is the optimal, given of the convenience for facilitating the voltage conversion and the ability to ease off the developing pressure facing Station 19. At this time, RoseHill DS is planned to be designed as a dual-transformer station, with six 8.3kV feeders, complete with all necessary ancillary equipment. The two 7.5/10MVA transformers with tie-bus/breaker in-between will meet the capacity need and provide full redundancy during the QEW-South conversion.

The alternative analysis below discussed a few options regarding how to proceed with the QEW-South conversion and the final configuration of Fort Erie downtown system. The performed study utilized Milsoft EA and GIS system to analyze QEW-South load flow and evaluate a number of alternatives to address the issues and challenges faced during the conversion.

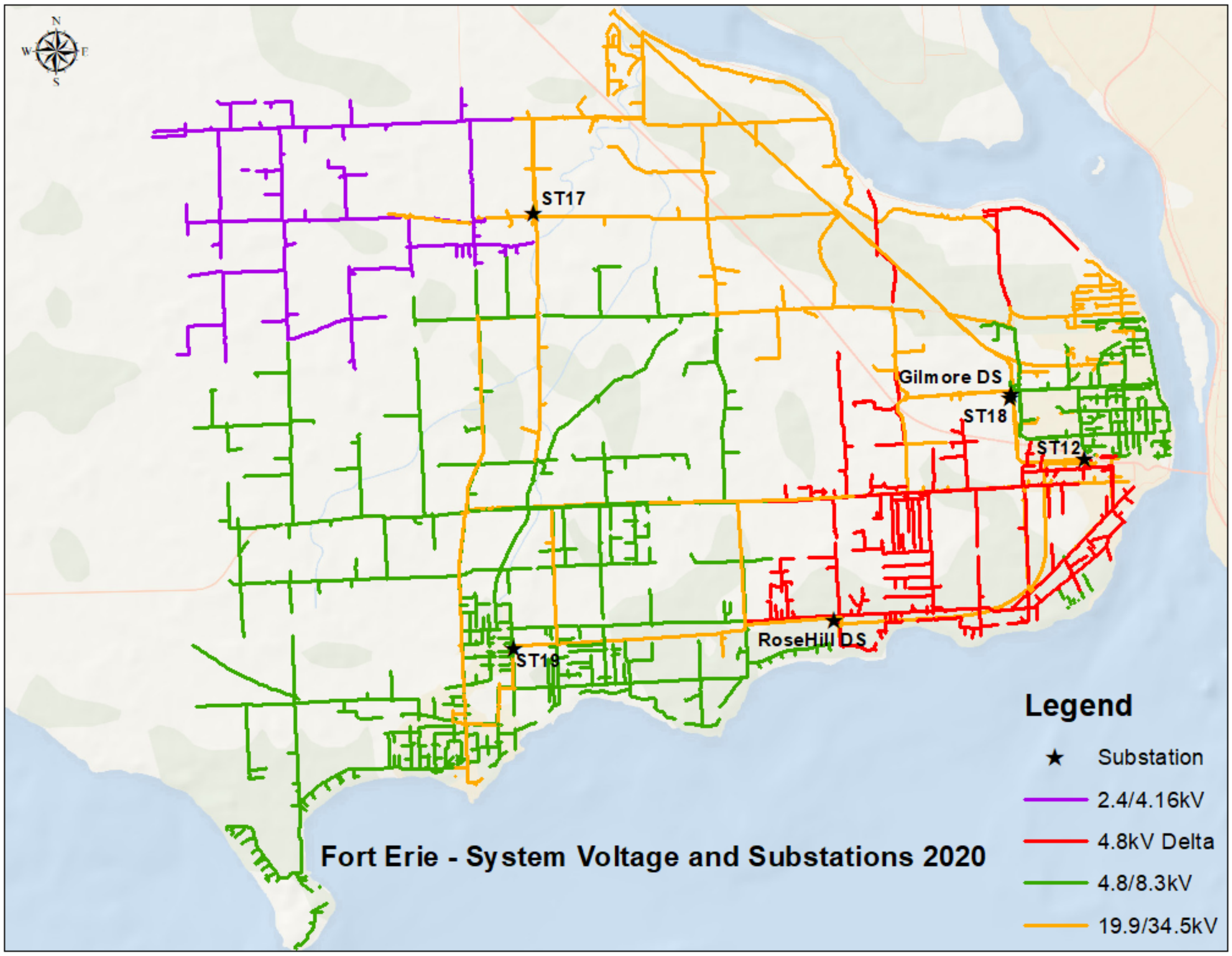


Figure 10: FE System by 2020 with the new Rosehill DS

5.1.1 Alt. A: Build 8.3kV Rosehill DS, Convert QEW-South, Re-Construct Station 12 (Oakes DS), and Re-configure ties among Gilmore DS, RoseHill DS and Oakes DS

QEW South system has two load centers: one is close to Crescent Park and one is close to downtown of Fort Erie. The legacy feeder configuration has a limited flexibility to switch the load evenly under contingency. Without a major line rebuild, one feeder may have to pick up an excessive chunk of load and be subject to overloaded conductors and equipment. Phase imbalance actually further exacerbates the problem and losses and voltage drop at a specific phase become issues when power is delivered from one load center to another.

Since Rosehill DS is geographically close to the load center of Crescent Park, but far away from the load center of Fort Erie downtown, after all the conversion is completed, a prominent question to ask is if another substation is necessary to be built on top of the decommissioned Station 12. Bearing in mind that it is almost impossible to find another location near downtown load center for a new substation. Should CNPI proceed to construct another substation, the legacy land of Station 12 with its current zoning code meets all the requirements regarding load distribution and environment assessment conditions.

In order to evaluate the necessity of the third substation after QEW-North and QEW-South conversion are all done and Rosehill DS and Gilmore DS are both in place, an engineering analysis was performed to examine if there is any concern about capacity, reliability, and voltage under normal operating condition and N-1 contingency scenario.

Figure 11 displays that under normal operating condition and assuming four RoseHill DS feeders to the east are in service, no voltage or overloading issues have been identified within Gilmore DS (QEW-North) and RoseHill DS (QEW-South) service territory. Only a few spans show over the thermal capacity limit due to legacy small conductor size, but this can be corrected during QEW-South conversion and feeder re-shuffling. However, under the worst scenario when Rosehill DS is out of service, Gilmore DS will have to pick up the loads of both QEW-North and QEW-South. **Figure 12** illustrates how the current four feeders of Gilmore DS will pick up the loads. Even the loads have been carefully split, Gilmore feeders are stressed out with 4.7MW, 4.5MW, 4.1MW, and 3.7MW separately; and the maximum phase current approaches 410Amps partially due to phase imbalance. **Figure 13** shows substandard primary voltages appear starting from the Crescent Park load center toward the furthest end of RoseHill DS territory.

Bearing in mind that the simulation above represents an N-2 contingency; since both Rosehill DS and Gilmore DS were designed to have six-feeder egress and two power transformers, in reality, this situation will rarely occur. Rosehill DS and Gilmore DS were designed to self-backed-up between their own two units. The necessity of the third substation (Oakes DS on top of Station 12) is essential only when one of the substations runs into a catastrophic event.

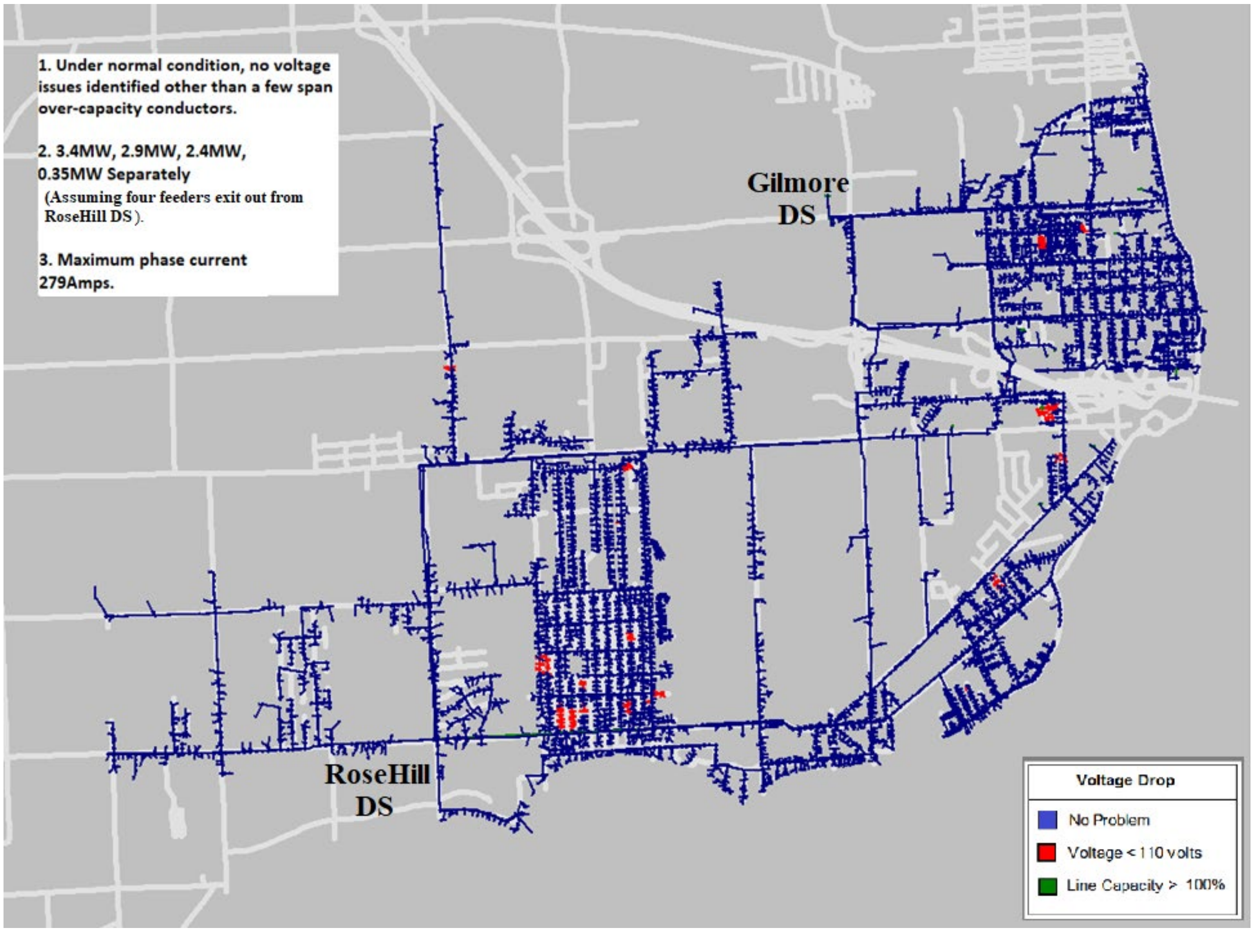


Figure 11: Gilmore DS and RoseHill DS under normal operating condition

As outlined in the DAMP-2016 (section 6.1.2), there are limited feeder ties to connect the South QEW area and the North QEW area after some of the legacy underground cables approach the end of life and retire as planned. The location and type of the remaining underground circuits make their replacement costs very high. In addition to underground ties, there is one legacy overhead tie that will be reserved after the whole voltage conversion is done. In total, the quantity of ties will be limited up to three.

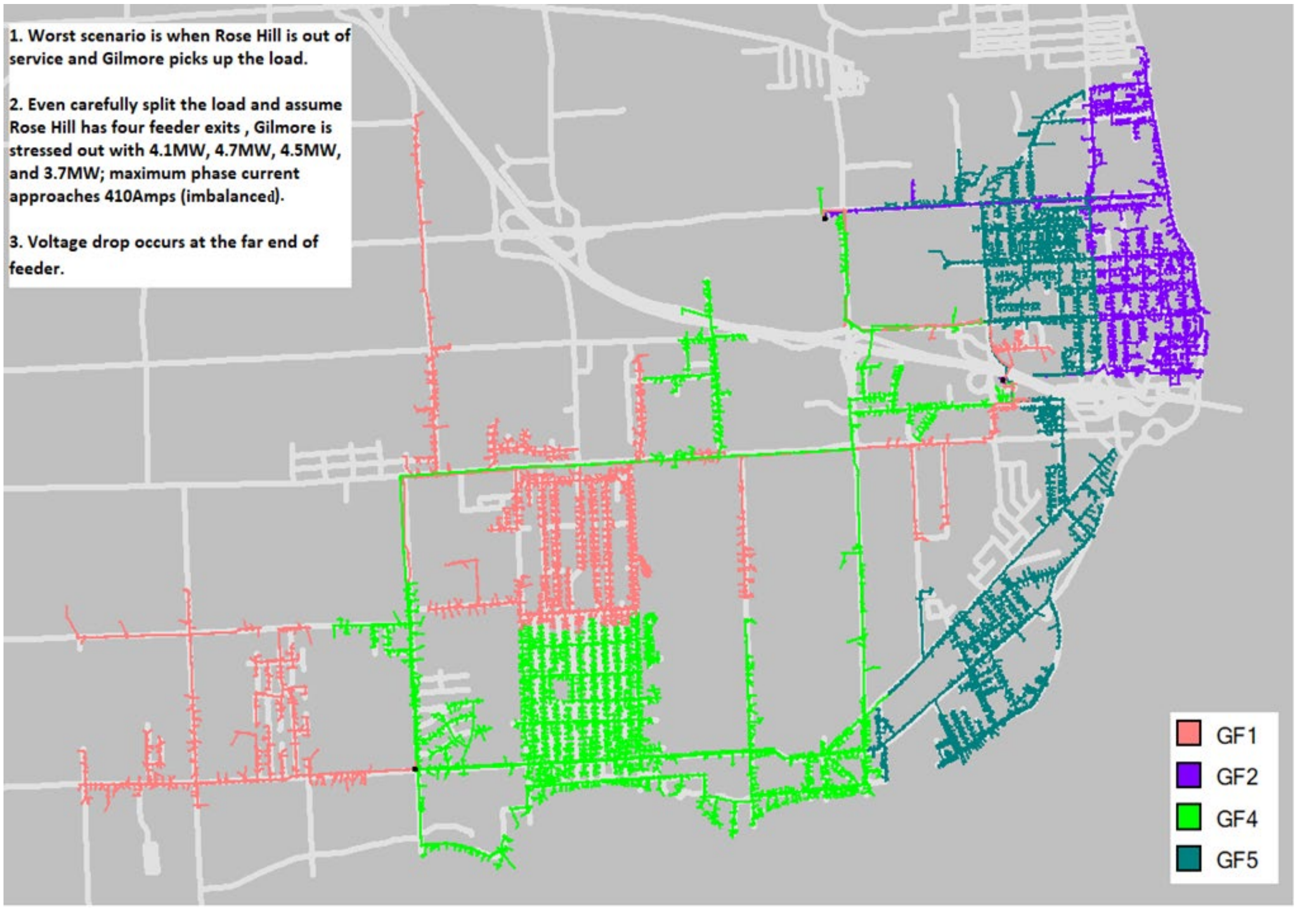


Figure 12: Gilmore DS to pick up RoseHill DS under worst scenario

From load growth perspective, QEW South area does not expect any significant load growth in the forecast period, however the growing cluster of new and emerging subdivisions since 2016 will re-shape the load distribution. Assuming a low steady growth rate at 1 percent per year, the load could grow by as much as 22 percent in 20 years and that will make the projected load in QEW South area 11.5MW. Furthermore, assuming uncontrolled EV connection (level 2 charger, 24A) with 25% EV penetration (2040 EV penetration level), the increment in loading from peak is about 20%, which will make the projected load in this area 13.8MW. As a long-term asset investment plan, CNPI's planning study has better to accommodate the reasonable growing capacity needs derived from technology innovations but avoid taking any aggressive approach in terms of load forecast.

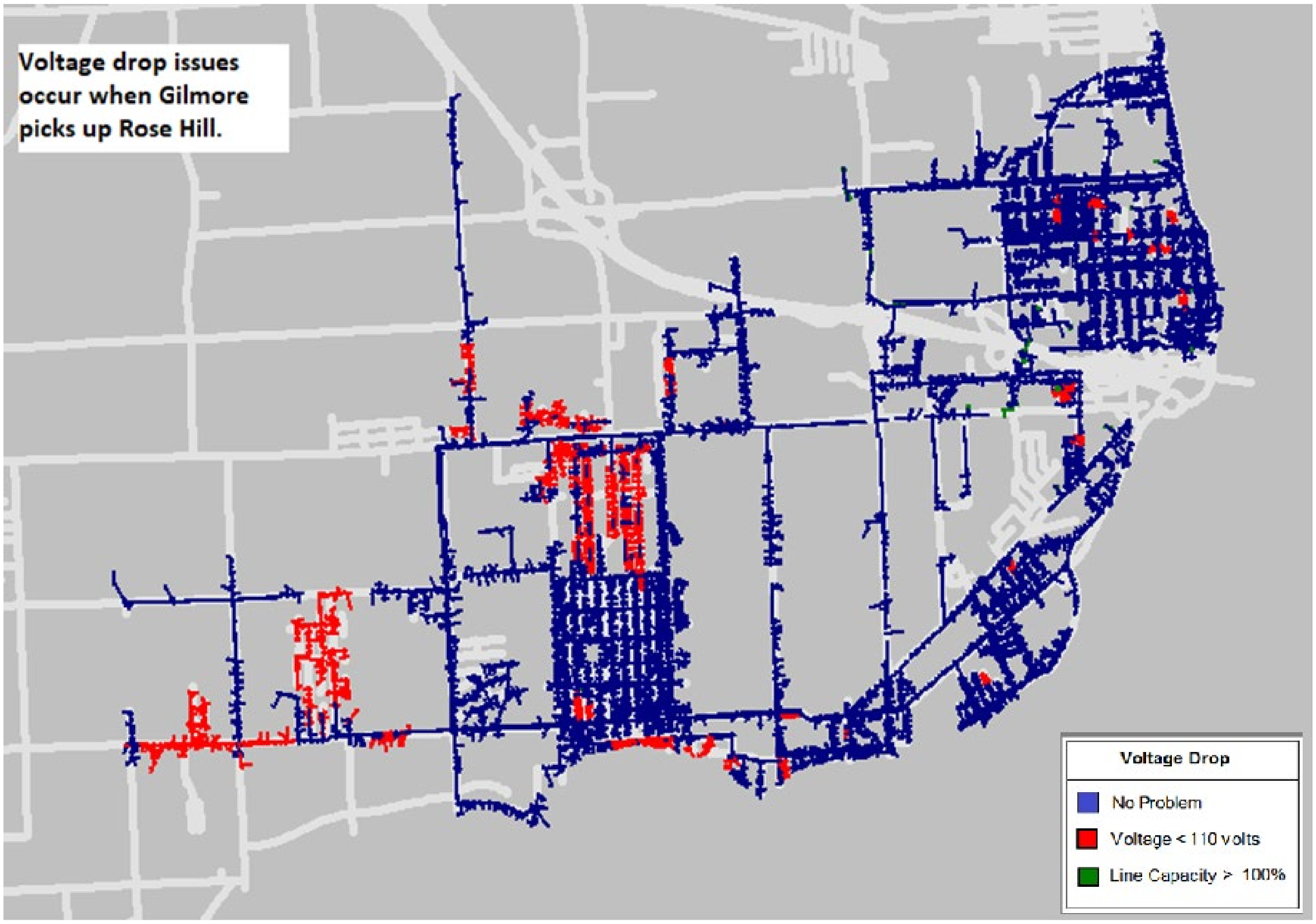


Figure 13: Voltage drop issue when Gilmore DS to pick up RoseHill DS

There is one specific consideration when designing Rosehill DS, which is the possibility to provide a backup to Station 19. Currently, all of Station 19's low-side (8.3kV) equipment is housed in a single metal-clad enclosure. This includes all feeder circuit breakers, metering, and protection & control (including SCADA). It is possible that one single catastrophic event could disrupt the ability of this switchgear to deliver any supply to the 8.3kV customers in its supply area. As outlined in section 3.3.1.3 of the DAMP-2016, at this time, Station 19 is the only such source available to this area. Some failure modes could disrupt delivery of power for quite long time. If the new RoseHill substation could provide some source relief to the service territory of Station 19, it will at least assure certain peace of mind in terms of reliability. An engineering study was performed to test the limit of loads capable of being supplied from RoseHill DS without experiencing major primary voltage drops. The study revealed that RoeseHill DS can provide a backup to Station 19 up to 3.6MW, without a major rebuild of today's feeder ties. As a result, given of the distance and the historical “out of phase” issue between RoseHill DS and Station 19, RoseHill DS will never be a full remedy for the challenges facing Station 19.

An engineering study was also performed to examine the loss savings with and without the third substation (Oakes DS). The analysis indicated that when total load of 9094KW was allocated to QEW-South, losses were about 590KW if RoseHill DS was the only source for QEW-South, while losses were 465KW if Oakes DS was in place to pick up loads close to Fort Erie down-town area. That makes the peak demand loss rate 5.12% with Oakes DS comparing to 6.49% without Oakes DS.

In summary, Alternative A has the following highlights:

- This option will pay high upfront cost incurred by the construction of two substations.
- This option can eliminate the concerns of substandard voltage issues under the contingency situation when Gilmore DS needs to backup RoseHill DS, or vice versa.
- This option is optimal from the load center distribution and loss saving perspective.
- This option offers the most flexibility in terms of switching and operating.
- This option provides enough capacity to accommodate a variety of growing demands, including uncontrolled EV connection with a moderate EV penetration rate.
- This option makes RoseHill DS a reliable partial backup source for Station 19, which can supply 3~4 MW at any time without stressing-out QEW-South load supply.

5.1.2 Alt. B: Build 8.3kV Rosehill DS, Convert QEW-South, Retire Station 12, and maintain three ties between Gilmore DS and RoseHill DS

As discussed in 5.1.1, this option will eventually have a limitation on the backup capacity between QEW-South and QEW-North without a major rebuild of primary trunk feeders and increased highway-crossing feeder ties. It may save some upfront cost of building a new substation, but when factoring in the long-term loss savings, the cost for Oakes DS will be really close to the cost of system rebuild. Further cost-benefit analysis is required to decide if this is an economic option.

In summary, Alternative B has the following highlights:

- This option DOES NOT address the concerns of substandard voltage issues under the contingency situation when Gilmore DS needs to backup RoseHill DS, or vice versa.
- This option is unfavorable from the load center distribution and loss saving perspective.
- This option poses inflexibility in terms of switching and operating.
- This option may encounter capacity problem if the EV penetration rate is too aggressive.
- This option makes RoseHill DS a partial backup source for Station 19 only when Gilmore DS is in full service.

5.1.3 Alt. C: Maintain "Status Quo"

Previous CNPI planning study had determined to convert QEW-North into 8.3 Wye system. As the conversion is near completion, maintaining Status Quo will not facilitate the inter-changeability of equipment and feeder contingency backup at a system-wide level. This option will leave QEW-North and QEW-South as two isolated systems. Gilmore DS and the aged Station 12 will be on their own.

Historically, 4.8∆ was the voltage that supplies QEW-South. As loads grow and feeders were required to reach longer distances, the 4.8∆ system became overloaded and start providing sub-standard voltage. This led to the subsequent installation of regulators and introduction of 34.5kV to correct the problem. The option of maintaining "Status Quo" calls for the installation of additional ratio banks to relieve the loads and shorten the reach of long 4.8Delta feeders. In some cases, the 34.5kV system would be extended to reach the points where these ratio banks are to be installed.

Ratio Banks have the advantage of low initial cost and quick deployment. However, they also create increased system complexity and high transformation losses. Furthermore, the small capacity of these units make them not very useful in outage situations. The legacy ratio banks in CNPI have historically been installed with different winding configuration (Δ-Y, Y-Δ, Y-Y), which causes their downstream feeders to become isolated systems and hardly to be paralleled with each other even though the nominal voltages are identical. Consequently, the overall strategy when correcting 4.8Δ system issues is to avoid adding more ratio banks.

Table 14 shows a preliminary cost evaluation of loss savings for the three options discussed above. Both Alt. A and Alt. B have noticeable annual cost savings, which makes Alt. C the least attractive option that would not be practical in improving the overall system reliability and loss performance.

Table 14: Alternative Comparison - Annual Energy Savings[4]

Alternative	Description	QEW-South Peak Losses (kW)	Load Factor	Annual Energy Technical Losses (kWh)	Annual Energy Savings (kWh)	Annual Cost Savings
C	Maintain Status Quo	778	0.55	2,567,657	/	/
B	Rosehill DS Only	590	0.55	1,947,195	620,462	$86,865
A	Rosehill DS and Oakes DS	465	0.55	1,534,653	1,033,004	$144,621

[4]: *Assuming $ 0.14/kWh and Loss Factor = 0.3*Load Factor + 0.7* Load Factor²*

In conclusion, Alternative A is the best option from the economical and project management perspective and it will make the upgrade of assets in poor condition to be an integral part of voltage conversion efforts.

Table 15 provided a rough estimate of work breakdown during QEW-South conversion.

Figure 14 displays an initial conceptual design of the backbone feeder of the proposed Rosehill with or without Oakes substation. Two feeders out of Rosehill DS exiting at Dominion Road and Rose Hill Road towards Station 19 will provide certain "break and make" backup to Station 19. Another four feeders out of Rosehill DS towards Crescent Park will form a triple to double-circuit loop along Dominion Rd, Garrison Rd, and Helena Street. If Oakes DS becomes part of the plan, three feeders out of Oakes DS will be tied with Rosehill feeders, so under normal operating condition, the two load centers will be supplied by its adjacent substation separately. Three highway-crossing ties, one overhead and two underground, will be maintained between Gilmore DS feeders and Oakes DS feeders, so the backup between QEW-North and QEW-South will be feasible. Along with the new-build of backbone 8.3Y feeders, the legacy 4.8Δ circuits will be either re-built, or refurbished, or quick-converted.

Table 15: QEW-South Conversion – Task Breakdown

Description	Quantity
Construct Rosehill DS (includes feeder exits)	N/A
Triple Circuit 3 phase Trunk - 8.3kV(Y) Build	1.6km
Double Circuit 3 phase Trunk - 8.3kV(Y) Build	3.7km
Double Circuit 3 phase Trunk - 8.3kV(Y) **Rebuild & Refurbish**	4km
Single Circuit 4.8(Δ) to 8.3kV(Y) **Rebuild & Refurbish**	26.5km
Single Circuit 4.8(Δ) to 8.3kV(Y) **Convert**	30.6km
Special Conversion work (includes 3 phase padmounts, primary services, stepdowns, etc)	3
3-phase OH transformer	35
3-phase UG transformer	4
1-phase OH transformer	321
1-phaseUG transformer	5
Construct Oakes DS (includes feeder exits)	N/A

Detailed transition plan with a yearly project breakdown, new feeder configuration, ties and backup strategy was outlined in a separate document. **Figure 15** demonstrates a prospective plan of the conversion assuming Oakes DS will be constructed. If the conversion progresses well, by the end of Year 2024, the backbone will be completed and QEW-South circuits will be converted,

An estimate of loss savings indicated that after the QEW-South is completely converted, the total Fort Erie system loss will reduce from 2928kW to 2672kW. This loss savings not only include savings due to increased system voltage, but also contains savings resulted from re-shuffling of the feeders and enlarging of the conductor size during the conversion.

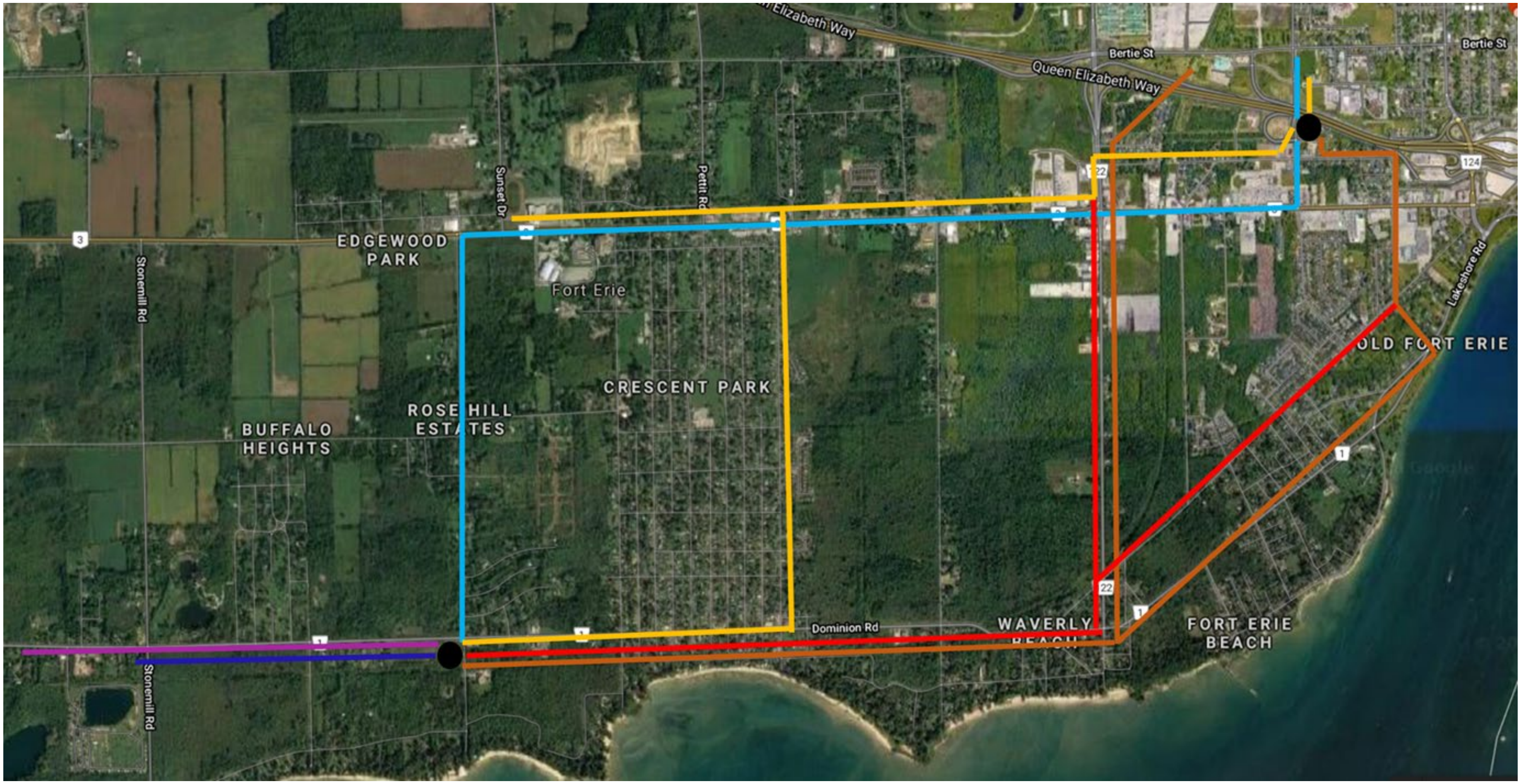


Figure 14: Gilmore DS and QEW-North Conversion – Conceptual Backbone Design

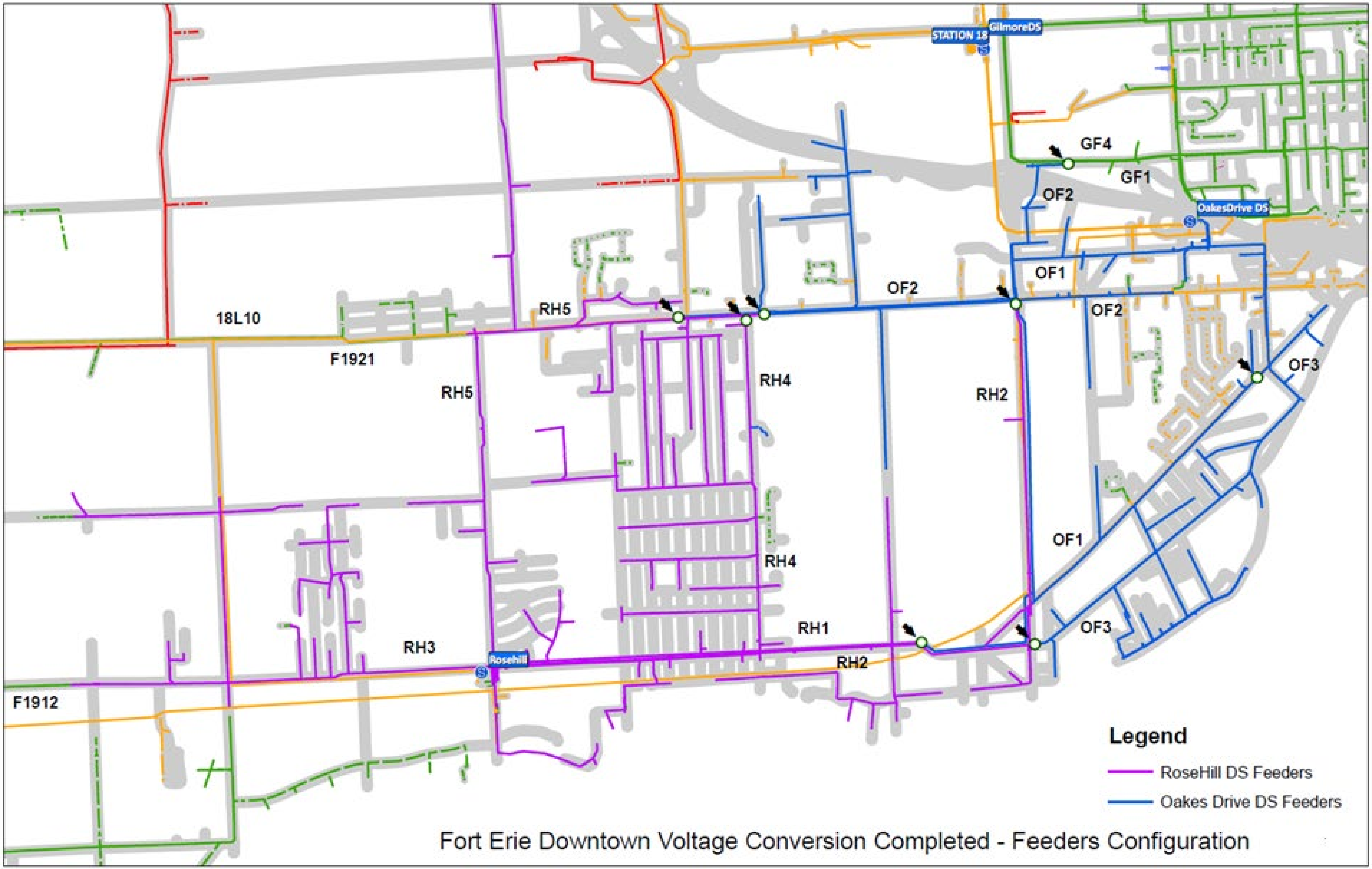


Figure 15: Prospective QEW-South Conversion with both Rosehill DS and Oakes DS

5.2 Stevensville Conversion and New Substation Construction

Stevensville represents an area that is currently supplied by three 3x500KVA ratio banks with rated output voltage of 2.4/4.16kV. It serves less than 1,000 customers, but a large portion of these residential loads are located in rural areas and have a long distance away from the source. In the past few years, various incidents and issues have revealed several items of concern that requires immediate attention. Challenges with existing system in Stevensville area include:

- **Small conductor size:** Out of the total 48km legacy overhead primary lines, 16.2km lines are identified as small conductors with a limited carrying capacity, for example, #2 or #4 Aluminum. The remainder of lines are mainly 1/0 or 3/0 ACSR. As illustrated in **Figure 16**, the sections of small conductors are generally either on the major feeder trunk or well away from the source. Consequently, they restrict the flexibility of feeder switching under contingency, put a curb on load growth, and cause voltage variations of customers near the feeder ends.
- **Vulnerable Supply from Ratio Banks:** At present, Stevensville is supplied via three structure mounted ratio bank transformers: 9RT1, 8RT1, and 8RT2. The ratio bank transformers have significantly contributed to a decline in reliability during events triggered by severe weather, overloading, or faults. The ratio bank transformers are more susceptible to impulse-related failures and deemed as vulnerable supply comparing to substation-class power transformers. As demonstrated in **table 16**, within the past five years (2016 to 2020), 65 outages were related to the failures of 7 major rabbit banks or their auxiliary equipment, including the 12 outages in Stevensville area.
- **Phase Imbalance and Voltage Drop issues:** The existing Stevensville system is especially inefficient due to constraints on voltage drop and phase imbalance. This poses challenges when connecting large loads or supplying enlarged seasonal loads. Obvious inefficiencies have been seen more frequently in recent years due to the increased complexity of the system. As illustrated in **Figure 17**, the red-highlighted area represents a large zone at the feeder end which can only be fed by a specific phase. During the cold days in the winter of 2017, numerous customers located near the end experienced voltage drop issues due to increased electrical heating demands; while switching the supply to downstream of a voltage regulator of another feeder, customers located near the new end started to experience voltage drops due to a newly-established large point load in their neighborhood. Temporary solutions had been implemented to address the

immediate needs, however, it becomes more and more imperative to seek a long term solution.

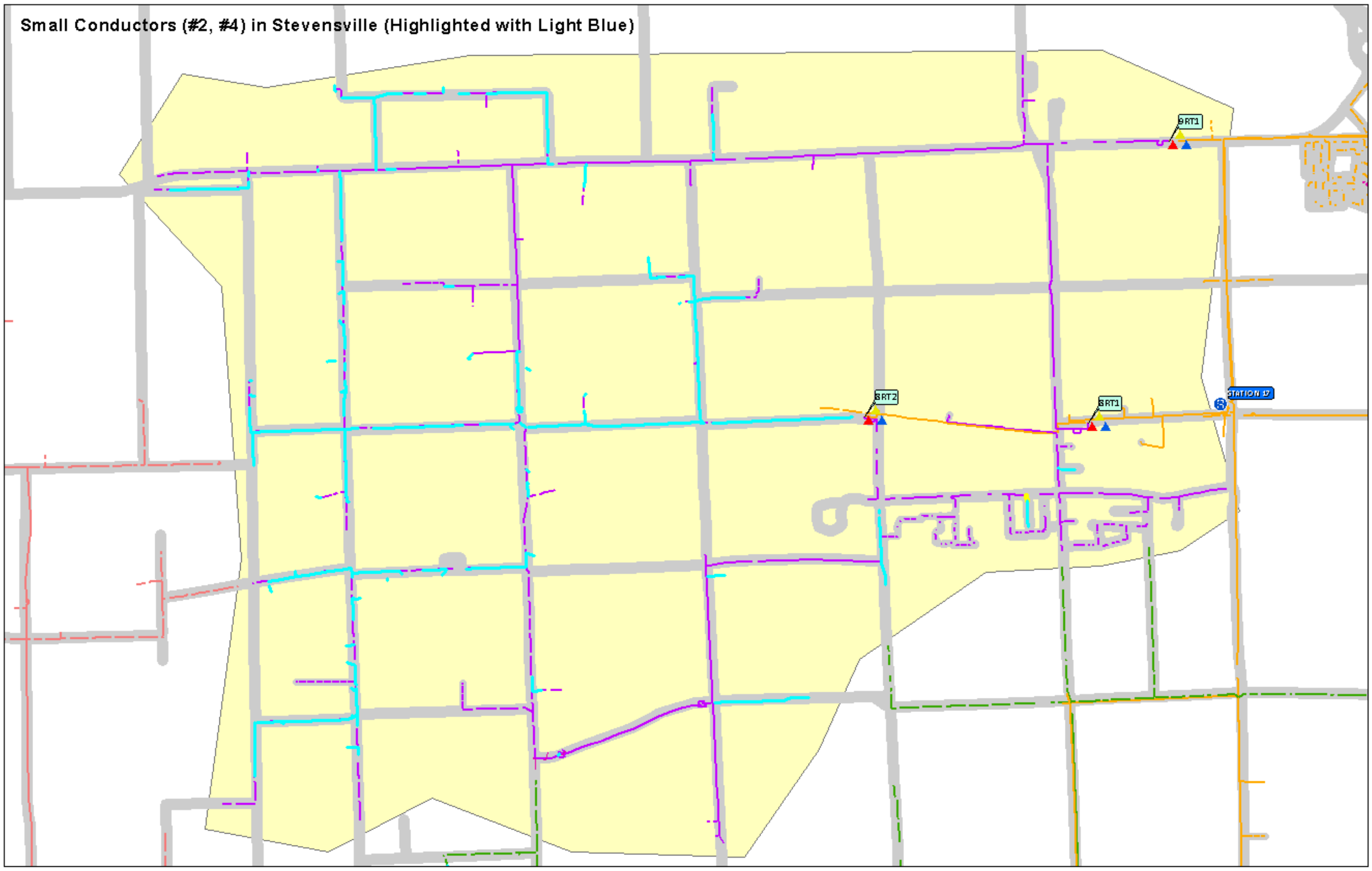


Figure 16: Small Conductors in Stevensville Area

Table 16: Outages related to Failures of a Ratio Bank

Trouble Element	RC10RT1	RC10RT3	RC67RT3	RC8RT1	RC8RT2	RC9RT1	RC9RT2
Outage Count	17	7	21	5	4	3	8
Average Duration (minutes)	367	1651?	142	3947?	76	262	451

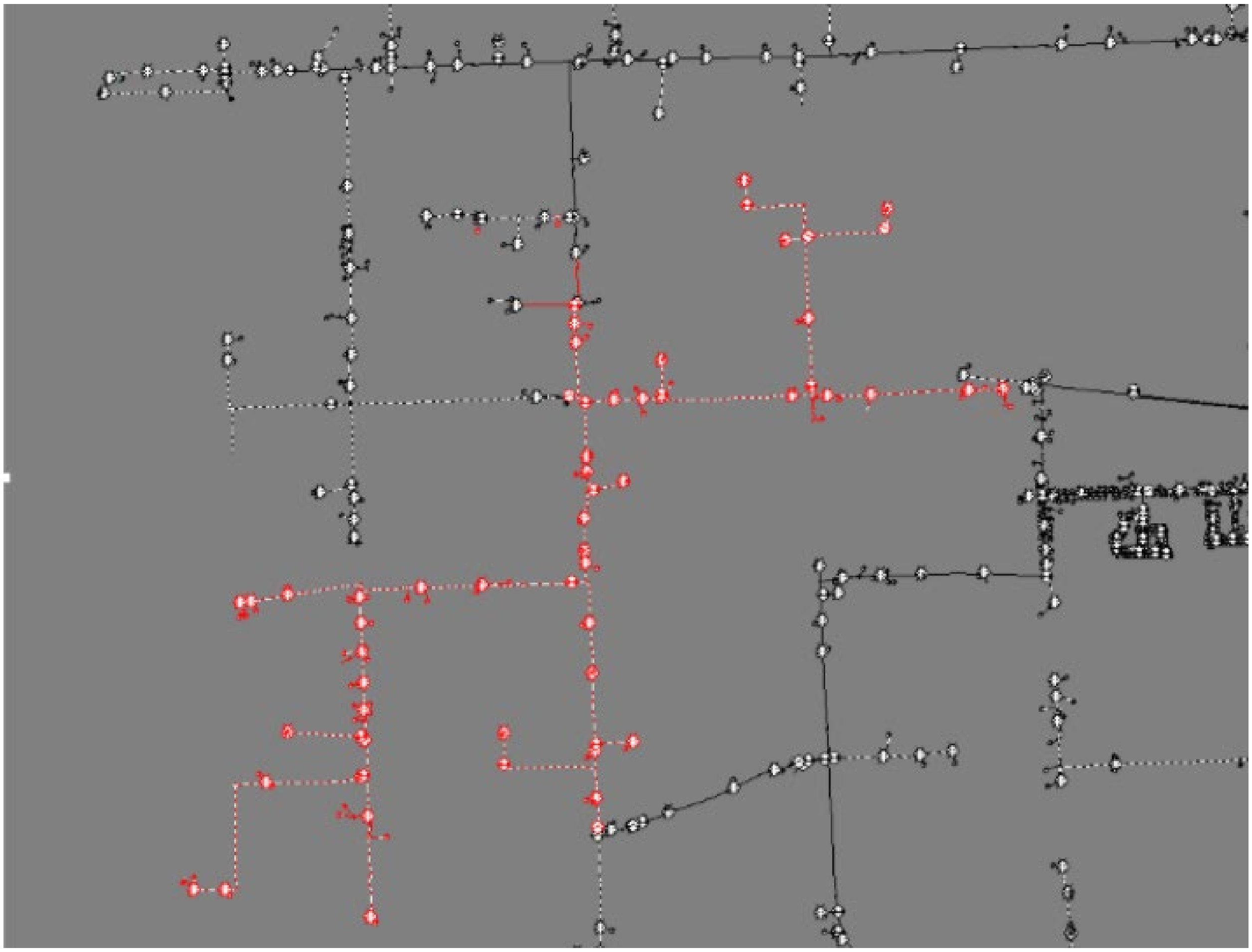


Figure 17: Phase Imbalance in Stevensville Area

Five alternatives were developed to address the challenges facing Stevensville today as below. The comparison of each option's peak demand losses, energy losses, and explicit financial cost associated with losses is demonstrated in **Table 17.**

5.2.1 Alt. A: Maintain Status Quo

This option does not address the concerns of the presence of the system nor does it result in any line-loss savings for a longer period of time. This alternative would mainly serve as a baseline for comparisons.

5.2.2 Alt. B: Construct a new 4.8/8.3kV substation and Implement a voltage conversion

This alternative would build a new single-element 8.3kV DS on a CNPI-owned property near the intersection of Eagle Street & Stevensville Road to improve the reliability. It would reduce line-losses through the voltage conversion and adjust the phase imbalance through new feeder configurations. Since the three legacy ratio banks can be re-wired to provide a 4.8/8.3kV output, they would remain on site and stay energized to back up the substation under contingency.

5.2.3 Alt. C: Construct a new 2.4/4.16kV substation and Replace small conductors on feeder trunks

This alternative would build a new single-element 4.16kV DS on a CNPI-owned property near the intersection of Eagle Street & Stevensville Road to improve the reliability. It would reduce line-losses through primary conductor replacements on major feeder trunks and adjust the phase imbalance through new feeder configurations. Three legacy ratio banks would remain on site and stay energized to back up the substation under contingency.

Table 17: Loss Comparison of Five Alternative

Option	Description	"Peak" Losses (kW)	Loss Rate	Load Factor	Annual Energy Technical Losses (kWh)	Annual Loss Cost
A	Maintain Status Quo	123.7	5.7%	0.55	408,251	$57,176
B	Substation (8.3kV)	59.9	2.75%	0.55	197,689	$27,685
C	Substation (4.16kV)	95.7	4.4%	0.55	315,842	$44,236
D	Ratio Bank (4.16kV re-conductor)	86.9	3.98%	0.55	286,799	$40,168
E	Ratio Bank (8.3kV re-conductor)	65.1	2.99%	0.55	214,851	$30,091

Assumptions:

- *Use summer peak load 2.18MW and its technical losses as a benchmark to estimate energy savings.*
- *A 25-year cost recovery period was used to estimate Savings arising from system loss reductions.*
- *Study assumes a flat energy price of $0.14/kWh but Future Value (FV) was derived assuming a constant increase of 2.0%/annum as an inflation factor.*
- *Present Value (PV) was discounted from future values using CNPI's WACC 2016, which is 7.18%/annum, as a constant discount factor.*
- *%E=(0.7*Load Factor+0.3)*D%*
- *So, if you know load factor and your technical losses (KW), you can calculate annual loss, e.g., 123.7*(0.7*0.55+0.3)*(0.55*365*24); in other word, you either know load factor and peak loss, or you know load factor and peak load.*

Based on a detailed planning study, Alternative B will need to re-conductor 5km single-phase lines into three phase to optimize the feeder configuration, while Alternative C will need to re-conductor 16.6km lines, either small conductors or single phase on major feeder trunks, to address the voltage drop and phase imbalance issues. Both alternatives will have to build a new 0.5km lines to facilitate the feeder egress. In addition, Alterative B will have an incremental cost on transformer replacement or re-wiring and the voltage conversion switching. The table below shows the cost comparison of Alternative B and Alternative C.

5.2.4 Alt. D: Maintain 2.4/4.16kV Ratio Banks but Replace small conductors on feeder trunks

5.2.5 Alt. E: Rewire Ratio Banks to 4.8/8.3kV and Replace small conductors on major feeder trunks

The five alternatives were subjected to a 25-year Net-Present-Value (NPV) evaluation of the energy savings and the results can be seen in the **Table 18** below.

Table 18: Alternative NPV Evaluation of Energy Savings

Option	Description	Annual Loss Cost	Non-Dual – Voltage TRFM Count	Re-conductor or New-built Lines	Line-cost	TRFM and Switching Cost adds-on	Substation Cost	Total Upfront Cost
A	Maintain Status Quo	$57,176	n/a	n/a	n/a	n/a	n/a	n/a
B	Substation (8.3kV)	$27,685	74	5km (re-conductor) 0.5km (new build)	$475,000	$132,300	$1,128,500	$1,735,800
C	Substation (4.16kV)	$44,236	n/a	16.6km (re-conductor) 0.5km (new build)	$1,320,000	n/a	$1,128,500	$2,448,500
D	Ratio Bank (4.16kV)	$40,168	n/a	16.1km (re-conductor)	$1,207,500	n/a	n/a	$1,207,500
E	Ratio Bank (8.3kV)	$30,091	74	9.7km (re-conductor)	$727,500	$132,300	n/a	$859,800

Unit Cost Assumptions:

- *New Build: $150,000/km*
- *Re-conductor: $75,000/km*
- *Total Switching Cost for Voltage Conversion: $25,000*
- *Labor Adds-on for Transformer Replacement: 1,600/Transformer*
- *Labor Adds-on for Transformer tap adjustment: $100/Transformer*
- *Estimates exclude new transformer cost assuming replaced functioning transformers will be re-used in the system elsewhere.*

Both Alternative B and Alternative C address the immediate need to increase the system reliability, eliminate the voltage drop and phase imbalance issues, and reduce system losses to some degree. As a result, a new substation along with the consequent feeder optimization will surely benefit the whole area over a long period of time.

However, Alternative C has much higher initial construction costs compared to Alternative B. It does not benefit to the same extent from the long term savings of reduced line-losses as Alternative B does. Another major advantage of Alternative B is the elimination of the 2.4/4.16kV operation voltage from Fort Erie system.

Should Alternative B be implemented, Fort Erie will be standardized with only two distribution voltages in the future: 19.9/34.5kV and 4.8/8.3kV. Therefore, the new substation will have the potential to back-up the feeders nearby from Station 19.

For these reasons, Alternative B is recommended.

Should Alternative B be implemented, the project will be completed in three stages:

- Stage 1: Engineering Design and Equipment Procurement (Year2022-Year2023)
- Stage 2: Substation Construction (Year2023)
- Stage 3: Voltage Conversion and Feeder Configuration (Year2024 – Year2026)

As illustrated in **Table 19**, the estimated total cost of substation (Stage 1 & Stage 2) is $1,625,870. Other than some of the engineering cost, most of this expenditure will be spent in Year 2022 and Year 2023. The estimated cost of Stage 3 is $607,300 and this expenditure will be spent between Year 2024 and Year 2026.

A conceptual system map as illustrated of **Figure 19** demonstrates the project goal by the end of Year 2026.

Table 19: Estimated Cost Breakdown with a Modular Design

Item	Description	Quantity	Unit Cost	Total Cost
1	**Modular Substation** (Transformer, HV/LV Vipers, Relays, Battery, Misc Comm, SS, Oil Collection)	1	$800,000.00	$800,000.00
2	Pole Work	3	$12,000.00	$36,000.00
3	1/0 kcmil 33%CN 38kV Cable	200	$40.00	$8,000.00
4	1000 kcmil 33% CN 15kV Cable	300	$50.00	$15,000.00
5	Terminations	24	$200.00	$4,800.00
6	Civil (Pad and Grounding)	1	$150,000.00	$150,000.00
7	Feeder Exits (separate OEB acct)	1	$200,000.00	$200,000.00
8	Engineering	1	$200,000.00	$200,000.00
Total Estimate for Modular				**$1,413,800.00**
Total Estimate w/ 15% Contingency $ 1,625,870.00				

Figure 18: Conceptual Modular Design of Stevensville DS

Figure 19: Stevensville DS Feeder Configuration by 2026

5.3 Station 19 Area Reliability Improvement

Station 19 area is currently supplied by two 10/13MVA transformers with rated output voltage of 4.8/8.3kV. It serves more than 5,600 customers and has load centers near Crystal Beach and Ridgeway areas. About ¼ of its residential loads are located in rural areas and have a long radial feed from the source far away. Challenges with existing system in Station 19 area include:

- **Need for source relief:** The low-side (8.3kV) equipment of Station 19 is housed in a single metal-clad enclosure. This includes all feeder circuit breakers, metering, and protection & control (including SCADA). It is possible that a single catastrophic event could disrupt the ability of this switchgear to deliver supply to the 8.3kV customers in its supply area. Some failure modes could disrupt delivery of power for several months. At this time, Station 19 is the only such source available.
- **Load growth in Crystal Beach area:** 2019 peak load of Station 19 was about 11.8MW, and the peak load for TB1 and TB2 was 3.9MW and 7.6MW separately. In the past few years, CNPI deliberately limited the access of industrial and commercial loads larger than 500KW to Station 19 feeders by diverting the connections directly onto the 34.5Kv system. However, the new subdivisions and residential developments have emerged steadily, especially adjacent to Crystal Beach area. Based on a moderate load forecast, Station 19 load will be increased to 13.8MW within 15 years. If a moderate EV penetration has been taken into account, the load will be increased to 16.6MW.
- **Point Abino reliability issue:** Within the same service territory of Station 19, a 3x500KVA ratio bank on Erie Road, 67RT3, supplies 569 customers along Erie Road and all the way to the Point Abino. Given of its geographical location, Point Abino area is highly susceptible to inclement weather and related outages. On top of that, the frequent reoccurrence of incidents due to failures of the ratio bank makes Point Abino the least reliable area. 67RT3 is a 34.5kV Wye to 4.8kV Delta bank. Currently, there is no other source available to directly back up 67RT3, while Station 19 feeders do exist nearby.

Two alternatives were developed to address the challenges facing Station 19 today as below.

5.3.1 Alt. A: Maintain Status Quo, install a 8.3kV-Wye to 4.8kV-Delta ratio bank near Crystal Beach

This alternative would keep the substation and its service territory "as-is" and only install a new wye-to-delta ratio bank tapped-off from F1911 feeder as a backup source for 67RT3. Minor improvements would be made through adjusting the ties among feeders to improve reliability and operating convenience.

This alternative is legitimate considering the facts as follows:

- An auto-transfer scheme had been recently established to minimize the outage time due to "loss of supply" at the HV-side of Station 19.
- An Arc-flash detection functionality had been recently added to the LV-side switchgear to minimize the chance of any disastrous failure of switchgear.
- The sixth feeder egress had been recently constructed to facilitate a better load distribution faster switching among Station 19 feeders.
- The new RoseHill substation could provide certain source relief to the service territory of Station 19, although given of the distance and the historical "out of phase" issue between RoseHill DS and Station 19, RoseHill DS will not be a full remedy for the challenges facing Station 19.
- Should a new 4.8/8.3kV substation in Stevensville be constructed, it will provide certain source relief to Station 19, even the capacity that can be transferred from Stevensville is intensely limited by the distance and current feeder configuration.

5.3.2 Alt. B: Construct a new single-unit substation near Crystal Beach, convert 67RT3 to 8.3kV-wye

This alternative would construct a new substation near the load center of Crystal Beach and then convert 67RT3 loads onto the new substation feeders and retire 67RT3. This option will address the concerns facing Station 19, but it will be costly.

Both Alternative A and Alternative B address the immediate need to increase the system reliability from the technical perspective. However, Alternative B has much higher initial construction costs compared to Alternative A. As a result, Alternative A is recommended from the cost-benefit perspective.

5.4 Other Major Projects

5.4.1 Catharine Substation

In 2019, CNPI completed the reconstruction of Jefferson substation according to an alternative analysis performed previously in 2017. In that study, it was identified that if both Jefferson DS and Catharine DS became unavailable, there would be issues with overloaded conductors and substandard voltages when Fielden DS is the only 4.16kV source to supply the west side of Welland Canal. Three options were evaluated and the recommended option was to re-construct Jefferson DS to follow the amount budgeted in DSP 2016 and replace Catharine DS in the near future.

Along with that plan, a few tasks were identified to be completed to ensure the system performance during the construction of Jefferson substations, including:

1. Guarantee two 27.6KV supplies for Fielden Substation
2. Build the egress of FF5
3. Upgrade approximately 2km of undersized conductors (primary trunk)
4. Re-evaluate the load increase and system configuration to determine the design requirements for Catharine DS

Task 1 and Task 2 were completed before Jefferson DS rebuild. Task 3 was not completed given that the sections with small conductors were usually located in high-density urban areas (as illustrated in **Figure 20**) and it is expensive to conduct line re-build. As a result, when Jefferson is out of service, its south-west-end loads still require to be picked up by Catharine feeders in order to avoid substandard voltages. From capacity perspective, Jefferson DS has a single unit with ONAN rating of 5MVA only, therefore rebuilding Catharine DS into a substation with similar capacity will offer greater flexibility in terms of switching and meet the requirements of both load increase and load distribution.

A conceptual design and one-line diagram are shown in **Figure 21** and **Figure 22**. This is just one of the options. Currently, a modular substation which integrates the power transformer with other substation equipment such as reclosers, relays, and load-break switches into one unit is also under evaluation.

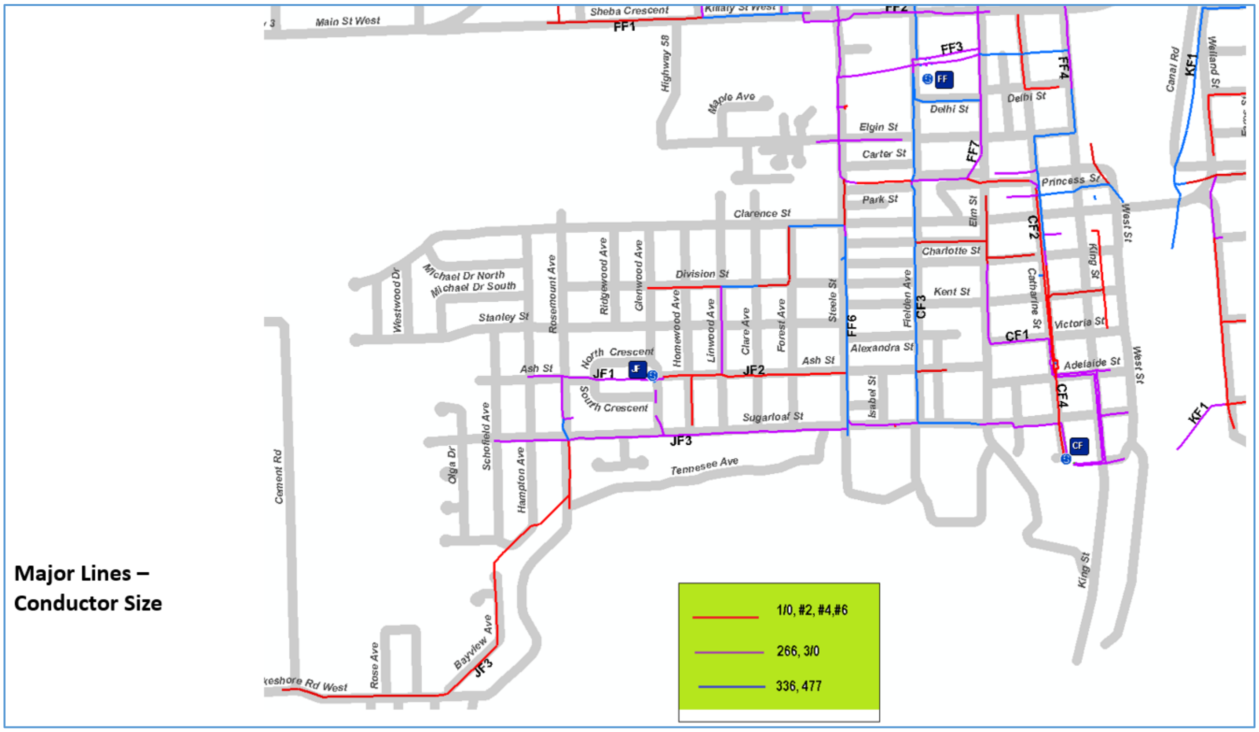


Figure 20: Major Line Conductors in Port Colborne South Area

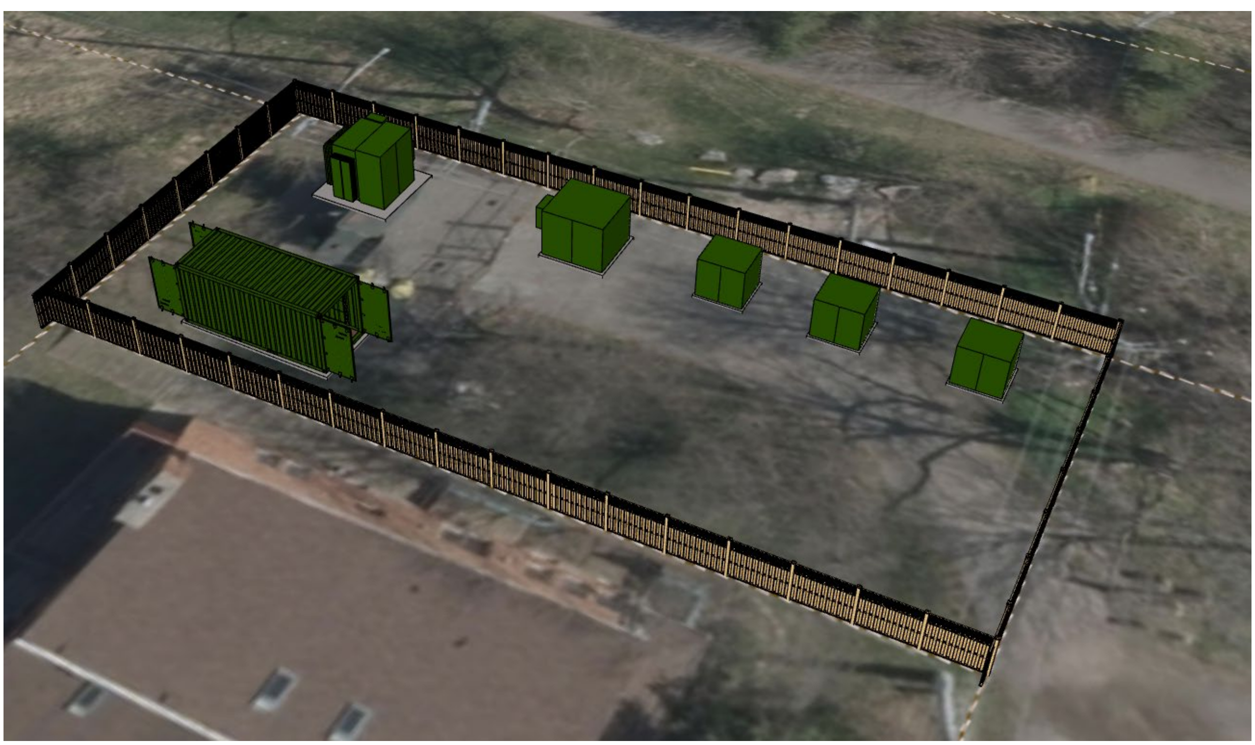


Figure 21: Conceptual Design of Catharine DS

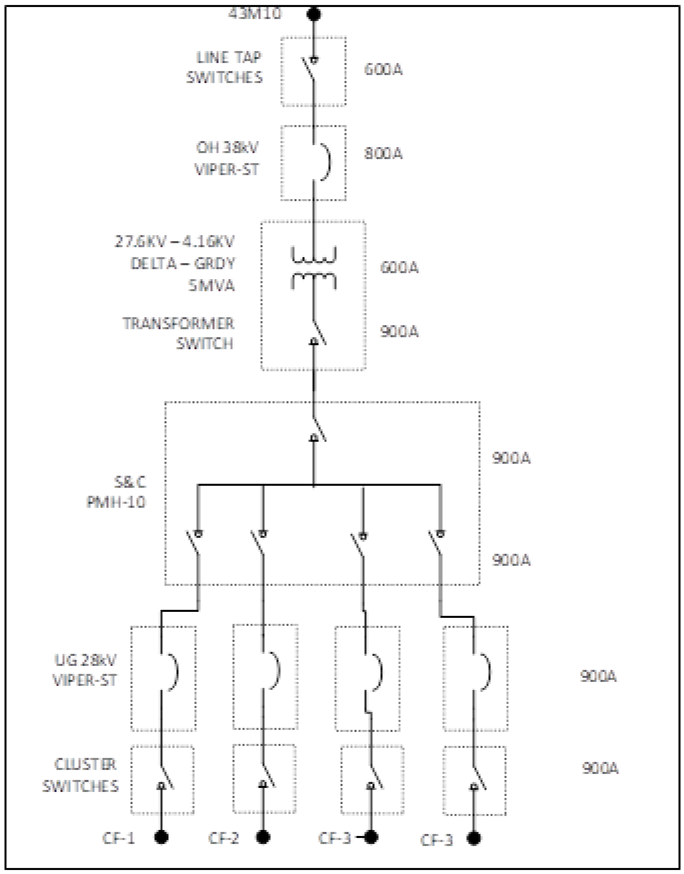


Figure 22: Conceptual Single Line Diagram of Catharine DS

5.4.2 Killaly Substation

Killaly DS is isolated from the rest of the 4.16kV substation sources by Welland Canal. There are no other DS to back up the supply if it were to become unavailable. There are a few small pole-mount ratio banks, but they are not sufficient to supply all the load of Killaly DS.

In the past few years, CNPI replaced the 27.6kV primary fuses with two pole-mount Viper reclosers equipped with modern SEL relaying and SCADA modules. Two sets of new 28kV ingress cables with the cable risers on separate poles were installed to supply Killaly East Bank and Killaly West Bank separately. This configuration and protection upgrade leveraged the capability of Killaly DS to minimize the risk of losing one bank or both banks, which could result in a prolonged power interruption to many Killaly customers. However, there is still just one single 27.6kV supply to this DS. The legacy low-side (4.16kV) switchgear presents another single point of failure which may significantly limit restoration options under contingency.

According to DSP 2016, the full protection and configuration upgrade for Killaly DS also included:

- Replacement of the vintage 4.16kV switchgear with a combination of deadfront equipment such as S&C PME switchgear or G&W Viper Padmounted reclosers.
- Installation of a second 27.6kV supply

In order to address the challenges facing Killaly, other than the option to continue the upgrade identified above, another alternative has been proposed to convert the load of Killaly DS onto 27.6kV feeder 43M12. This option will address the issue of no-back-up source; however, it requires a substantial asset replacement since the operating voltages are in different insulation class. **Table 20** summarizes the total asset within Killaly service territory.

Table 20: Asset Summary of Killaly DS Service Territory

Description	Quantity
Three Phase Line	12.45km
Single Phase Line	10km
3-phase OH transformer	26
3-phase UG transformer	1
1-phase OH transformer	122
1-phaseUG transformer	0
Customer	1450

5.4.3 Distribution Automation

For a number of years, CNPI has been engaged in a Distribution Automation program that leverages its investments in SCADA, GIS and Outage Management systems (OMS) to improve operational efficiencies and improve reliability.

These include:

- Automated line reclosers complete with SCADA
- Automated three-phase load-break switches, complete with SCADA
- LOV (Loss of Voltage) and FLISR (Fault Location, Isolation, and Service Restoration) distribution automation system, complete with upgraded SCADA – Port Colborne DA Pilot project 2020
- Fault Indicators that help in identifying the location of faults to the CNPI distribution system. CNPI is investigating the suitability of SCADA-able units.
- Integration of Smart Meters with OMS to provide near-real-time identification of system outages at the consumer level.

Although CNPI's SAIDI and SAIFI trending is positive over the historical period, feeder level analysis (*refer to the reliability study performed by SNC*) still indicates that there is room for improvement on specific line sections. CNPI intends to continue with its efforts to target poorly performing feeders with the automation improvements through the installation of reclosers, automated switches, fault indicators, LOV/FLISR, and the integration of such facilities with its SCADA and Outage Management System (OMS) applications.

This will not only have a clear impact on reliability statistics and overall system reliability, but also provide a labour savings option when applied on protection and switching devices that are remote from the service center.

5.5 Common Measures

Other than the projects defined above, the following measures should be given attention and blended into the overall picture:

- Field-check non-standard secondary voltages indicated in this study and address locally if confirmed
- Conduct a statistical study on the transformers indicated as potential over-loaded in this study and document the ones that call for larger ratings
- Investigate the need for size upgrade on conductors (primary and secondary) that showed over-capacity under peak or contingency situation
- Investigate the potential load imbalance issues and non-standard voltage in the sensitivity analysis of this study

6 Major Project List (2021-2026)

ID	Area	Project Description	Category
1	FE	Decommission ST12 and Rebuild Crossings or Construct New Oakes DS	SR
2	FE	QEW South 4.8Δ to 8.3Y Voltage Conversion	SS
3	FE	QEW South 4.8Δ to 8.3Y Rebuild	SR
4	FE	QEW North 4.8Δ to 8.3Y Rebuild	SR
5	FE	Stevensville - 4.16Y to 8.3Y Voltage Conversion	SS
6	FE	Stevensville - 4.16Y to 8.3Y Rebuild	SR
7	FE	Construct New Stevensville DS	SR
8	PC	Construct Catharine DS	SR
9	CNPI	Distribution Automation & Reliability Improvements Program	SS
10	FE	Retire 18L10 along Friendship Trail	SS
11	FE	Build Rosehill DS double-circuit towards Station 19	SR
12	FE	67RT3 Backup Source	SR
13	CNPI	Targeted Pole Replacement Program	SR
14	PC	Killaly DS – Switchgear Upgrade (or *Voltage Conversion / Rabbit Backup*)	SS
15	CNPI	Pole Testing Program	SR
16	PC	New PC TS – Feeder Exits	SR
17	CNPI	Substation Project Group 1 - New Equipment/Device/Facility	SR
18	CNPI	Substation Project Group 2 - Equipment Upgrade	SS
19	CNPI	Meter Misc.	SR/SS
20	CNPI	Line Project Group 1- Fault Indicator/Protection upgrade – including 115kv	SS

21	CNPI	Line Project Group 2 - Wildlife Protection, Fuse Link Replacement	SS
22	CNPI	Line Project Group 3 – Distribution System Upgrade (Misc.)	SR/SA/SS
23	CNPI	43M12 Rebuild – Pending on Sherkston Resort loading	SR/SA
24	CNPI	OT Cyber Security	GP
25	CNPI	Tools & Equipment	GP
26	CNPI	Fleet/Stock/Easement/Environment Management Program	GP
27	CNPI	Information Technology – Hardware	GP
28	CNPI	Information Technology – Software	GP

Appendix A – Gananoque Area Addendum

1. EOP - 4.16kV to 27kV Rebuild & Voltage Conversion

According to DSP 2016 5.4.6.12, the long-term goal for EOP is to eventually convert all of the 4.16kV distribution system to 27.6kV. There are two major economic returns supporting this conversion. One is in loss savings of reduced primary conductor line-losses. The other major contributor to the savings is the avoided cost of having to upgrade/replace major pieces of equipment (transformers, breakers, relaying) within Herbert Street DS and Gananoque DS. By transferring load over to the 27.6kV distribution system, EOP could gradually retire these distributions stations.

During 2017 to 2020, EOP took advantage of the rebuild projects along Pine Street and Coopers Alley and completed a 27.6kV loop between Herbert DS and Gananoque DS. The extensive 27.6kV not only provides supply redundancy to Herbert DS but also provides the convenience for converting end-of-life 4.16kV assets to 27.6kV in the downtown area.

The original conversion plan was to reduce the peak load on the 4.16kV distribution system from 10.6MVA to 5MVA through voltage conversions and then retire an end-of-life station transformer in Gananoque DS while maintaining N-1 contingencies on the 4.16kV system without the need to replace this asset in-kind, due to reduced load levels. However, the subsequent investigation identified that the substation structures of Gananoque DS were in poor conditions, and since it is located on the bank of Gananoque River, which is considered an environmental sensitive area, the land lease agreement for Gananoque DS may have to be terminated by the end of 2022. After detailed studies and discussions with the Town of Gananoque, EOP cannot find a proper piece of land to construct a new DS to meet both the environmental and system configuration requirements. As a result, a “distributed ratio banks” option was developed. This option involved installing four or five 2 MVA pad-mounted 27.6kV to 4.16kV transformers at selected locations to provide backup for Herbert DS and to pick up some loads after the de-commissioning of Gananoque DS. This option also assumed that 3.7km three phase lines and 5.3km single phase lines (about 2.5MVA) will be gradually converted from 4.26kV to 27.6kV near the time of Gananoque DS being retired.

EOP will install the ratio banks in 2021 and actively convert feeder GA-11 and GA-7 during 2021 to 2023. One of ratio banks that is used to facilitate the GA-7 conversion will be relocated to a better strategic location in order to provide further operation flexibility.

In addition to downtown and Gananoque River west bank conversion, the scope of EOP's distribution system upgrade program also deals with the distribution system along the West line (~80km). In order to meet its asset management sustainment goals, EOP must make capital investments towards rebuilding an average 1.6km along the West Line per year in order to keep up with aging infrastructure. Considering the complexity of downtown and Gananoque River west bank conversion, the resources and investments will be focused on this area over the next two to three years and the West Line conversion will be possibly resumed after.

2. EOP – Distribution Automation & Reliability Improvements

This multi-year program is aimed at the introduction of field based automated switching and protection devices. Based on analysis of reliability data, EOP targets sections of feeders with poor performance and implements automation designed to decrease outage frequency and duration and to improve overall response time. With the planned decommissioning of Gananoque DS and implementation of the "distributed ratio banks" approach, the automated switching and protective devices will significantly alleviate the operation inconvenience.

The installations typically consist of a motor operated switch or recloser coupled with protective relaying and control devices. The resulting installation is capable of remote interrogation and operation via EOP's SCADA system. In general, those devices will limit the section of line impacted by downstream faults, allowing restoration of the majority of customers upstream from an adjacent circuit when required.

Except for substation breakers, EOP currently only has one line recloser installed and will install four more for the distributed ratio bank transformers. EOP's Investments in the forecast period will target poorly performing or remote sections with the automation improvements at a rate of one to two units per year.

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

DSP APPENDIX F:
CNPI RELIABILITY STUDY

FortisOntario Technical Service Contract

RELIABILITY STUDY

Final REPORT

SLI PROJECT NO.: 657327

0	Issued for Revision	26/11/2018	MOA	TA	TA
REV.	DESCRIPTION	DATE	PRPD	CHKD	APPRD
			SNC-Lavalin		

Executive SUMMARY

This is the final report of the study entitled "Distribution System Reliability Study for API and CNPI" which commenced in July 2018. This study, undertaken at the request of FortisOntario, Ontario, Canada, is conducted by SNC Lavalin Inc. Toronto, Canada, as the Consultant. The study objective is to analyze the historical distribution line outage information, identify the major causes of line outages, and recommend actions required to reduce customer-hour outages.

The outage analyses considered the calculation of the reliability indices for the whole CNPI system (i.e. SAIDI and SAIFI). Figure ES-1 shows the reliability indices trend for years 2011 – 2018. The trend for the reliability indices in CNPI increased dramatically in 2015 and 2016 followed by improvement in 2017 to 2018.

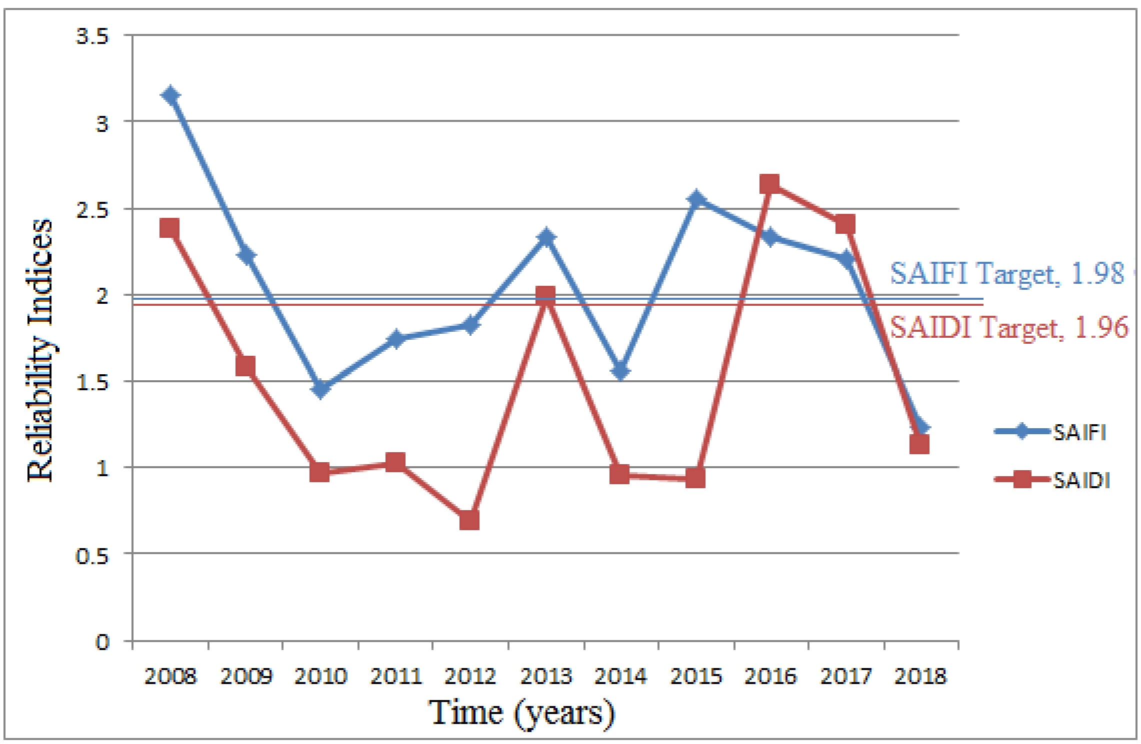


Figure ES-1 Reliability Indices Trend for CNPI System

To give some specific recommendations to enhance the reliability indices for CNPI, a more detailed study for the causes of the outages for different substations and feeders were performed. The main outage causes in CNPI found to be Vegetation, Power Supply (Planned and Unplanned Transmitter Outages), and Equipment Failure from interruption duration perspective as shown in Table ES-1.

Table ES-1 Main Outage Causes

Cause	Sum of Customers affected	Ratio of Total Customers Affected	Sum of Customers Interruption Durations (Min)	Ratio of Total Interruption Durations
Equipment	355044	13.75%	8052427	12.25%
Power supply	286148	11.08%	22541653	34.30%
Vegetation	449671	17.42%	12700159	19.327%

The outage study showed more than 83% of the customers affected and Interruption Duration occurs at the service are five substations (i.e., **Pt Colborne** , **Station 17, Station 18, Station 19, and Jefferson**) as shown in Table ES-2.

Table ES-2 Outage Data for the Main Substations of CNPI

Substations	Sum of customers affected	Sum of interruption durations (Min)
Pt Colborne	**1238297**	**18760277**
Station 17	**558581**	**15819594**
Station 18	**525628**	**11298516**
Jefferson	**31584**	**10349901**
Station 19	**324431**	**7723338**

The detailed outage study for the different feeders within CNPI showed that out of the total of 127 feeders, only five feeders (i.e., 17L67, 43M10, 43M9, 1923 and 18L10) are responsible for more than 34% of the total outages as presented in Table ES-3.

Table ES-3 Outage Data for the Main Feeders of CNPI

Feeder	Sum of customers affected	Sum of interruption durations (Min)	Substations
17L67	261841	5878911	**Station 17**
43M10	321034	4863508	**Pt Colborne**
43M9	198076	4717737	**Pt Colborne**
1923	197568	3940653	**Station 19**
18L10	137447	3276438	**Station 18**

The study recommends the following initiatives and actions to help CNPI reducing customer-hour outages and to improve the reliability:

Vegetation Management Recommendation: the recommendation to reduce one of the main outage causes (i.e., Vegetation), is to revisit the vegetation management plan, especially for selected areas that causing more outages than others. Table ES-4 presents the areas of the main five substations; those areas should have more frequent vegetation management cycles (i.e., every year).

Table ES-4 Areas of the Five Main Substation

Substations	Covering Areas
Pt Colborne	**Service areas of feeders:** 43M9, M9RT3, RCM9-1, M9RT16, 43M10, 43M11, M10RT6, M11RT10, M12RT17, 43M12, M12RT1, M12RT4, M12RT5, M12RT7, M12RT8, M12RT11, M12RT12, M12RT14
Station 17	**Service areas of feeders:** 17L5, 17L8 17L9, 17L67, 8RT1, 9RT1, 9RT3, 67RT1, 67RT3, STATION 13, STATION 19, RC17L8-1, 67RT2, 67RT4, 8RT2
Station 18	**Service areas of feeders:** 18L5, 18L8, 18L10, 18L11, 5RT7, 5RT1, 5RT2, 5RT3, 5RT6, 10RT1, 10RT2, 10RT3, 11RT1, 10RT4, 10RT5, RC18L10-2
Jefferson	**Service areas of feeders:** RCM10-1, JF1, JF2, JF3
Station 19	**Service areas of feeders:** 1911, 1912, 1913, 1921, 1922, 1923, RC1921-1

Equipment Maintenance Recommendation: the recommendation to reduce the equipment outages is to revisit the feeder maintenance plan for the main feeders that causing more outages than others. Table ES-5 summarizes the main feeders that causing outages and the corresponding suggested equipment maintenance schedule (i.e. every two years).

Table ES-5 Feeder Maintenance Recommended Schedule

Substations	Feeders	Current Maintenance Schedule	Recommended Maintenance Schedule
Station 17	17L67	2015, 2019, 2027	2015, 2019, 2021, 2023, 2025
Pt Colborne	43M10	2013, 2016, 2021	2013, 2016, 2020, 2022, 2024
Pt Colborne	43M9	2015, 2019, 2027	2014, 2017, 2019, 2021, 2023, 2025
Station 19	1923	2015, 2018, 2023	2015, 2018, 2020, 2022, 2024
Station 18	18L10	2014, 2022, 2030	2014, 2019, 2021, 2023, 2025

Increased CNPI Coordination with Transmission Operator Planned Outages: Another recommendation which could help CNPI to reduce the outage time effectively and hence improve the reliability indices is the coordination between the planned outages of CNPI and the planned outage of the transmission operator, so CNPI needs an enhanced planned outage management system. This improved outage management system can coordinate the planned outages to be done at the same time of the transmission planned outages.

Feeder Automation Recommendation: One of the effective methods to reduce the equipment failure outages is the equipment automation approach, for example, automated feeder switching which can be accomplished by automatic reconfiguration and isolation of segments of distribution feeders. The automated feeder switches will response if a fault condition is identified locally or to a control signal sent from another location. The operation of multiple switches can be coordinated to clear faulted portions of feeders and reroute power to and from portions that have not experienced faults; those actions can reduce the number of customers who experience sustained outages and the average duration of outages.

Because switches are one of the major outage causes, one solution for CNPI is to examine the retrofitting of major switches with new switches equipped with control packages. The control packages include user interfaces and communications systems that enable equipment to be programmed and controlled remotely. The controllers open and close the switches independently, or in combination with other switches, depending on the programmed logic and system conditions. The switches can be controlled and operated remotely by CNPI operators or CNPI distribution management systems. To reduce outage with transformers, adding remote monitoring and communication capabilities for some of the critical transformers can allow CNPI to conduct predictive maintenance (PM) of transformers, which means conducting maintenance when a parameter starts deviating from a pre-set standard. Remote management allows CNPI operators to see and monitor how a transformer is operating, and interfere when it's necessary.

With FA technology, this entire restoration operation can be done in less than one minute. In comparison, manual operation of switches by line crews typically takes between two and four hours to achieve the same restoration of power to unaffected customers. Thus, FA can limit the number of customers impacted by an outage on a trunk feeder and it dramatically improves restoration times. The feeders presented in Table ES-6 represent the worst feeders experiencing the largest outage durations. Automation of these feeders would greatly enhance the system reliability.

Table ES-6 Candidate feeders for Feeder Automation

Feeder name	Number of affected customers	Interruption duration (Minutes)
17L67	261841	5878911
43M10	321034	4863508
43M9	198076	4717737
1923	197568	3940653
18L10	137447	3276438

The cost estimate for the Feeder Automation option is presented in Table ES-7. The switches to be automated are the main switch, the sectionalizers, and the tie switches. The average feeder automation cost (installation and upgrading costs per feeder) is C$ 300k-400 k.

Table ES-7 Cost Estimates of Feeder Automation

Hardware	Cost ($)	Cost with Overheads ($)
Switch for Overhead Distribution including the SCADA/software and communication upgrades	61,200	70,380

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1 Introduction

This is the final report of the study entitled "**Distribution System Reliability Study for API and CNPI**" which commenced in July 2018. This study, undertaken at the request of FortisOntario, Ontario, Canada, is conducted by SNC Lavalin Inc. Toronto, Canada, as the Consultant.

FortisOntario is the holding company that owns a 100% of the following Local Distribution Companies ("LDC") in Ontario:

1. Canadian Niagara Power Inc. ("CNPI") and also includes the subsidiary Eastern Ontario Power (EOP).
2. Algoma Power Inc. ("API")
3. Cornwall Electric ("CE")

Algoma Power Inc. ("API") and Canadian Niagara Power Inc. ("CNPI") are looking for analyzing the historical distribution line outage information and identifying the major causes of line outages. The study will help API and CNPI in evaluating the recommended actions to reduce customer-hour outages. In that context, FortisOntario hired SNC-Lavalin to perform the reliability analysis study. The reliability study comprises different power system studies on several scenarios in order to identify system performance issues

The overall objective of the reliability study is to analyze the historical distribution line outage information (SAIDI, SAIFI), identifying major causes of line outages, and recommending actions to reduce customer-hour outages. The specific objectives are the following:

a) Review and analyze historical outage information (This report summarizes the findings of this task)
b) Identify opportunities to reduce customer outage hours
c) Recommend options to improve system reliability

2 Analysis Approach

Algoma Power Inc. (API) and for Canadian Niagara Power Inc. ("CNPI") are looking for analyzing the historical distribution line outage information and identifying the major causes of line outages.

Reliability evaluation of Algoma Power Inc. (API) and for Canadian Niagara Power Inc. ("CNPI") distribution utilities is performed through historical assessment of the system outage and customer interruption data. The historical distribution line outage information is analyzed by consistently logging the frequency, duration, and causes of system component failures and customer interruptions and identifying major causes of line outages.

The reliability study starts with analyzing historical distribution line outage information (SAIDI, SAIFI, CAIFI and CAIDI). Then, the major causes of line outages will be identified. Finally, the recommending actions to reduce customer-hour outages will be determined. The opportunities to reduce customer outage hours and frequency of interruptions will be identified by preventing outages, reducing the number of customers impacted, reducing the restoration/outage identification time, and recommending options to improve system reliability.

The reliability indices used in conducting the reliability study are defined according to the IEEE Std. 1366 as follows:

- **System average interruption frequency index (SAIFI)**
  The system average interruption frequency index indicates how often the average customer experiences a sustained interruption over a predefined period of time.
- **System average interruption duration index (SAIDI)**
  This index indicates the total duration of interruption for the average customer during a predefined period of time. It is commonly measured in customer minutes or customer hours of interruption.

The classification of outage causes is performed based on the IEEE Std. 1782-2014 (IEEE Guide for Collecting, Categorizing, and Utilizing Information Related to Electric Power Distribution Interruption Events), as presented in Table 2-1.

Table 2-1 Classification of outage causes

Category	Description
Equipment	Any piece of the distribution system equipment that is defective or fails and causes an interruption to customers should be put in the equipment category. A few examples of equipment types include controls, conductors, insulated transitions, interrupting devices, arresters, structures and supports, switches, and transformers.
Lightning	The lightning category includes all interruptions caused by lightning. This may be by a direct stroke contacting the wires or another piece of equipment, or by a lightning-induced flashover of the wires or another piece of equipment.
Planned	The planned category includes, but is not limited to Road construction, maintenance and repairs, load swaps, replacing equipment, and house moves. Typically, planned interruptions are those interruptions that can be delayed by the utility personnel and performed only after the appropriate or required customer notification. Often, regulatory commissions have specified rules describing planned interruptions.
Power supply	The power supply category includes interruptions caused by a failure in the transmission system including the transmission portion of a substation or the loss of a generating unit including those associated with distributed generation. It does not include outages due to the loss of a distribution substation component.
Public	Any interruptions resulting in the act of the public at large should be put into the public category. Examples include customer trouble, non-utility employee or contractor dig-in, fire/police requests, foreign contact (such as Mylar balloons, crane boom, and aluminum ladder), traffic accidents, vandalism, and fires and explosions not originating on or within the utility-owned equipment.
Vegetation	The vegetation category includes interruptions caused by falling trees or limbs, the growth of trees, vines, and roots. It should be emphasized that if a tree is involved, the cause category is vegetation.
Weather	The category of weather should include interruptions due directly to a weather phenomenon including wind, snow, ice, hail, and rain where the weather itself caused the interruption and exceeded the system's design limits. Wind does not include slapping or galloping conductors; those would go under the equipment category. Ice forming on conductors and tearing them down or flooding of power facilities would be included in the weather category.
Wildlife	This includes mammals, birds, reptiles, and insects, or any other non-human member of the animal kingdom. Wildlife can cause interruptions directly through contact, like snakes, mice, ants, raccoons, squirrels, or birds; or indirectly, like nests and bird excrement.
Unknown	The unknown category includes any customer interruptions where a definitive cause cannot be determined after investigation. The level of investigation required is determined by the individual utility.
Other	Any interruptions to customers that do not fall into any of the other cause categories should be assigned to the other category. Some examples include errors in construction, maintenance, operating, or protecting; overload; and contamination.

For the distribution feeders under study, SNC-Lavalin performed reliability analysis to identify the major causes of line outages for the system under operating conditions by performing the following steps:

- Temporal classification of the available historical outage data
- Reliability indices calculation.
- Classification of the outage data according to causes to identify major interruption causes.
- Classification of the outage data based on feeders and substations to identify major interruption cause for each feeder/substation.
- Revision of the current reliability enhancement programs, and the equipment aging.

3 Reliability Analysis for CNPI

CNPI distribution system consists from two main companies; CNP which covers Fort Erie area, and PCH which covers Port Colborne area. The total number of substations for CNP is eight, and the number of substations for PCH is ten stations. The feeders are rated at different voltages, including 34.5 kV, 27.6kv, 8.32kv, 4.8kv, 4.16 kV, and other miscellaneous voltages. The total number of customers is 26,148. The connectivity of the substations with the feeder for CNP is presented in Table 3-1, and for PCH is presented in Table 3-2.

Table 3-1 CNP distribution system connectivity

Substations	Names of feeders connected to Substation
Station 11	Station 17, Station 18
Station 12	STATION 12 B3, STATION 12 B1, STATION 12 B2, 1265, 1268, 1270, 1271, 1262, 1263, 1264, 1266, 1261, 1267, 1269, 1272, Station 12
Station 13	1361, 1362, 1363, 1364, 1365, 1366
Station 15	STATION 15, 1561, 1562, 1563
Station 17	17L5, 17L8, 17L9, 17L67, 8RT1, 9RT1, 9RT2, 9RT3, 67RT1, 67RT3, STATION 13, STATION 19, RC17L8-1, 67RT2, 67RT4, RC17L67-1, 8RT2
Station 18	18L5, 18L8, 18L10, 18L11, 5RT7, 5RT1, 5RT2, 5RT3, 5RT6, 10RT1, 10RT2, 10RT3, 11RT1, RC18L10-1, 10RT4, 10RT5, RC18L10-2
Station 19	1911, 1912, 1913, 1921, 1922, 1923, RC1921-1
Hydro One Murray HONI	Murray HONI, Station 11

Table 3-2 PCH distribution system connectivity

Substations	Names of feeders connected to Substation
Killally	KF1, KF2, KF3, KF4
Pt Colborne	43M9, M9RT3, M9RT16, 43M10, M10RT6, 43M11, M11RT10, M12RT17, 43M12, M12RT1, M12RT4, M12RT5, M12RT7, M12RT8, M12RT11, M12RT12, M12RT14, RCM11-2, RCM11-1, BLD – 13, RCM12-1, RCM12-2, 41M13, SF5, RCM9-1, RCM12-3
Catharine	CF1, CF2, CF3, CF4
Jefferson	JF1, JF2, JF3, RCM10-1
Fielden	FF1, FF2, FF3, FF4
Barrick	BF1, BF2
Sherkston	WF1, WF2, Wilhelm, SF1, SF2, SF3, Sherkston DS
Welland Hydro	Welland Hydro12F1
Niagara Falls Hydro	NIAGARA FALLS HYDRO NF1
Hydro One	Hydro One Port Colborne TS

3.1 Reliability Indices Calculations for CNPI

The available outage data (2008-June 2018) for CNP and PCH are chronologically classified, the total numbers of customer suffered from interruptions as well as the total number of customer interruption durations due to all causes are determined for each year separately. The results of the chronological classification are presented in Table 3-3 for CNP and in Table 3-4 for PCH.

Table 3-3 CNP chronological outage data classification

Year	Sum of Customers affected	Sum of Customers interruption duration (Minutes)
2008	230812	3180854
2009	174361	3319338
2010	134514	1189795
2011	107494	800551.1
2012	112101	9278683
2013	137636	2849717
2014	94402	1740567
2015	182552	2080042
2016	85332	2274647
2017	105753	6482344
2018	122924	4638892

Table 3-4 PCH chronological outage data classification

Year	Sum of Customers affected	Sum of Customers interruption duration (Minutes)
2008	64763.00	992946.33
2009	119192.00	596161.13
2010	89087.00	929959.28
2011	60939.00	985369.48
2012	41626.00	276916.73
2013	34138.00	1040042.43
2014	103103.00	654006.25
2015	82914.00	1199505.53
2016	170023.00	10950922.40
2017	192549.00	2957815.63
2018	135129.00	7290960.60

The SAIDI and CAIDI reliability indices are then calculated for CNPI (based on a total number of customers equals 26,148 customers) for each year for two cases; the first case excludes planned, power supply, weather, and lightning causes as well as momentary outages, while the second case includes all causes of the outages. The results of the calculated reliability indices are presented in Figure 3-1 for the first case, and in Figure 3-2 for the second case. Moreover, the SAIDI and SAIFI reliability indices introduced in the scorecard is presented in Figure 3-3. All of the calculated reliability indices are compared to the target set by CNPI; i.e. SAIDI target value of 1.96 and SAIFI target value of 1.98 as shown in the figures.

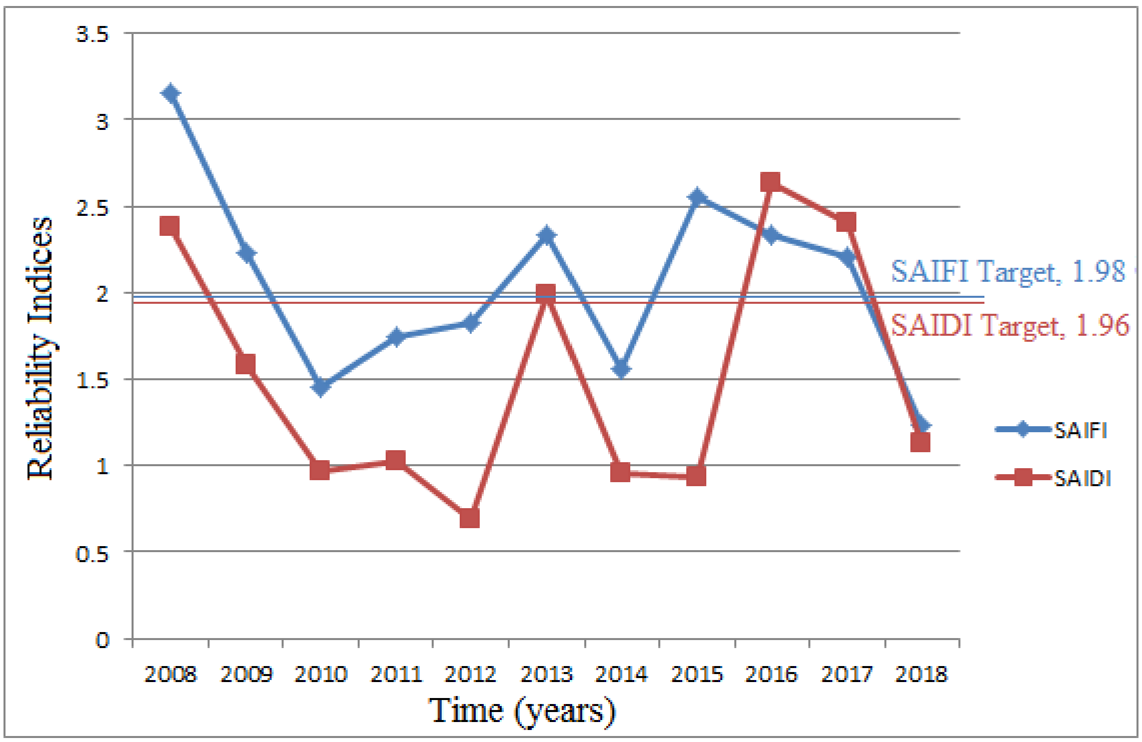

Figure 3-1 Reliability indices for CNPI while excluding momentary, weather related, and power supply outages

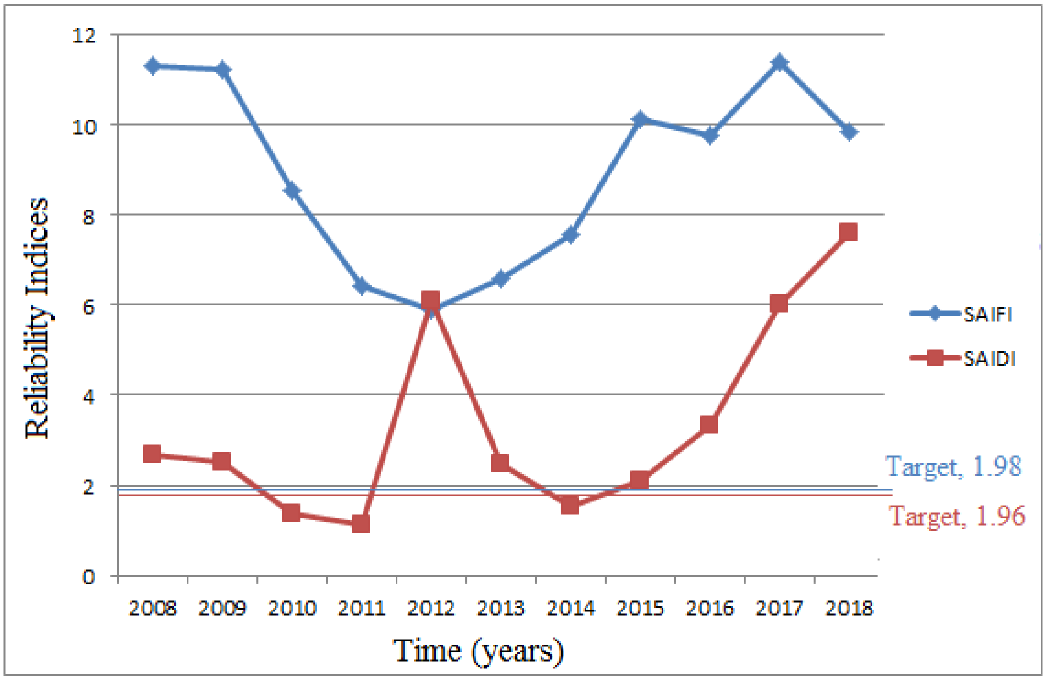

Figure 3-2 Reliability indices for CNPI while including all outages events

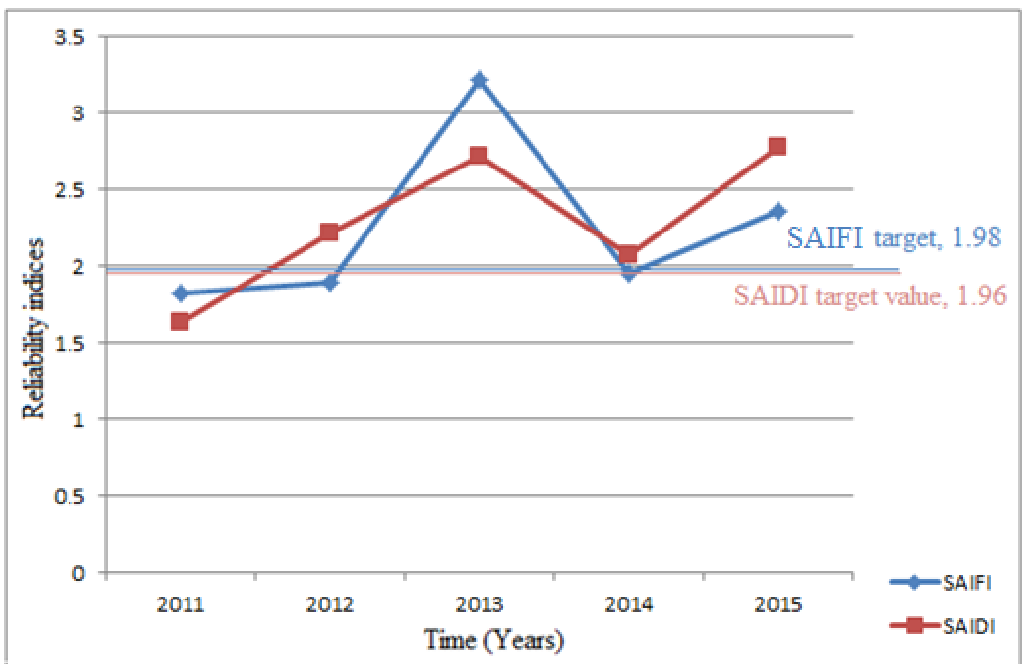

Figure 3-3 Reliability indices for CNPI from scorecard

3.2 Analysis of the Reliability Indices Trend

The reliability analysis shows that CNPI has a trend of reliability indices increase especially in 2015 and 2016. From the perspective of interruption durations, the main outage causes for years 2015 and 2016 are presented in Figures 3-4 and 3-5 respectively. The main outage causes are weather, vegetation, equipment, and supply for year 2015. While for year 2016, the main outage causes are equipment, planned, and vegetation.

A further analysis is carried out for the primary cause for year 2015; i.e. weather and the primary cause for year 2016; i.e. equipment failure. For year 2015, the weather outages for CNP represent 64.8 % of total weather outages occurred in CNPI. Two major weather related event for this year were recorded on Nov. 12th with 4412 customers affected and sum of 146,107 minutes of interruption duration. These two events cause a significant increase in the affected customers and the interruption durations, and consequently the reliability indices for year 2015. For year 2016, the equipment related outages for PCH represent 78.6% of the total equipment outages. Several major equipment related event for this year were recorded on Dec. 14th with 12,294 customers affected and sum of 1,119,310 minutes of customers interruption duration.

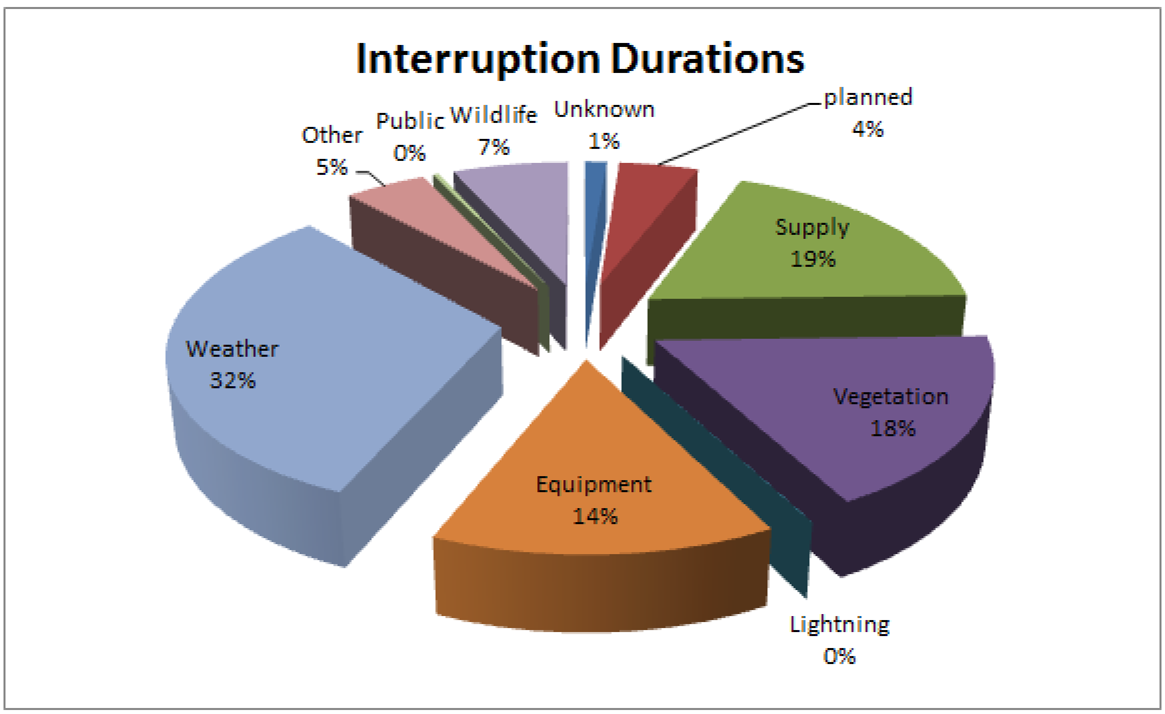

Figure 3-4 Interruption duration percentage per cause for CNPI, year 2015

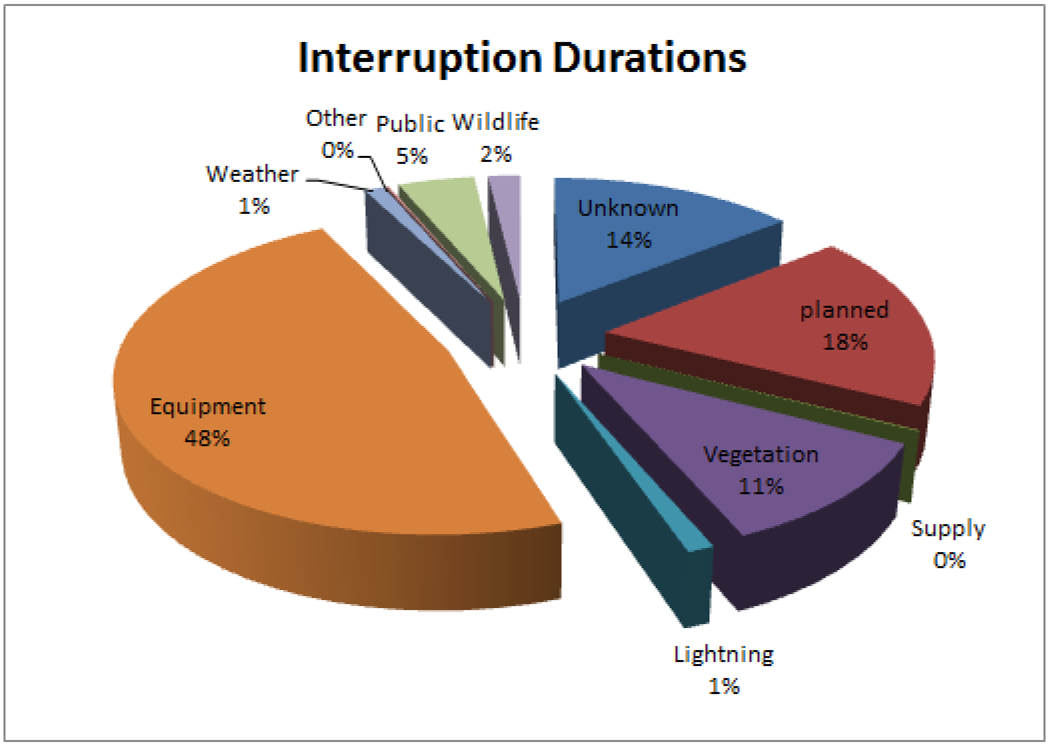

Figure 3-5 Interruption duration percentage per cause for CNPI, year 2016

The trend for the main outage causes; i.e. weather, vegetation, equipment, and planned outages, for the last four years are presented in Figures 3-6. The figure show significant improvement of the controllable outage events (i.e. planned, equipment, and vegetation events) in the recent two years. Moreover, the figure shows high deterioration for the uncontrollable outage events (i.e. supply and weather events) especially the outage caused by power supply unavailability.

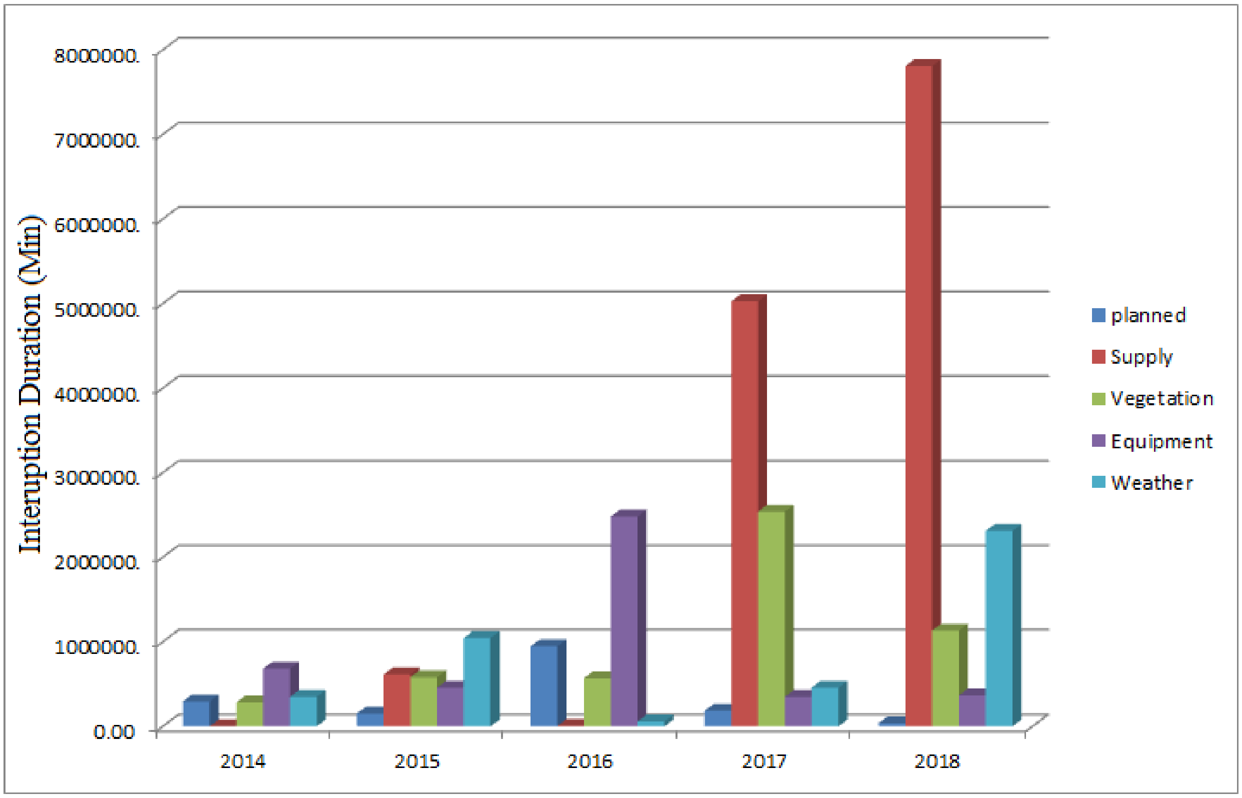

Figure 3-6 Outage causes trend for CNPI

3.3 Outage Causes Classification for CNP

The available outage data are classified according to causes based on the IEEE Std. 1782-2014 (IEEE Guide for Collecting, Categorizing, and Utilizing Information Related to Electric Power Distribution Interruption Events), as described in section 4. The total numbers of customer suffered from interruptions as well as the total number of customer interruption durations due to all causes are determined for cause separately. The results of the classification are presented in Table 3-5, Figure 3-7, and Figure 3-8.

Table 3-5 CNP outage causes classification

Cause	Sum of Customers affected	Sum of Customers interruption duration (Minutes)
Equipment	159097	3532451
Lightning	148985	1213922
Planned	42188	1568908
Power supply	175866	14126741
Public	36204	919752
Vegetation	373119	9544146
Weather (other than lightning)	216173	3705262
Wildlife	99580	714165
Unknown	211256	2143083
Other	25413	366998

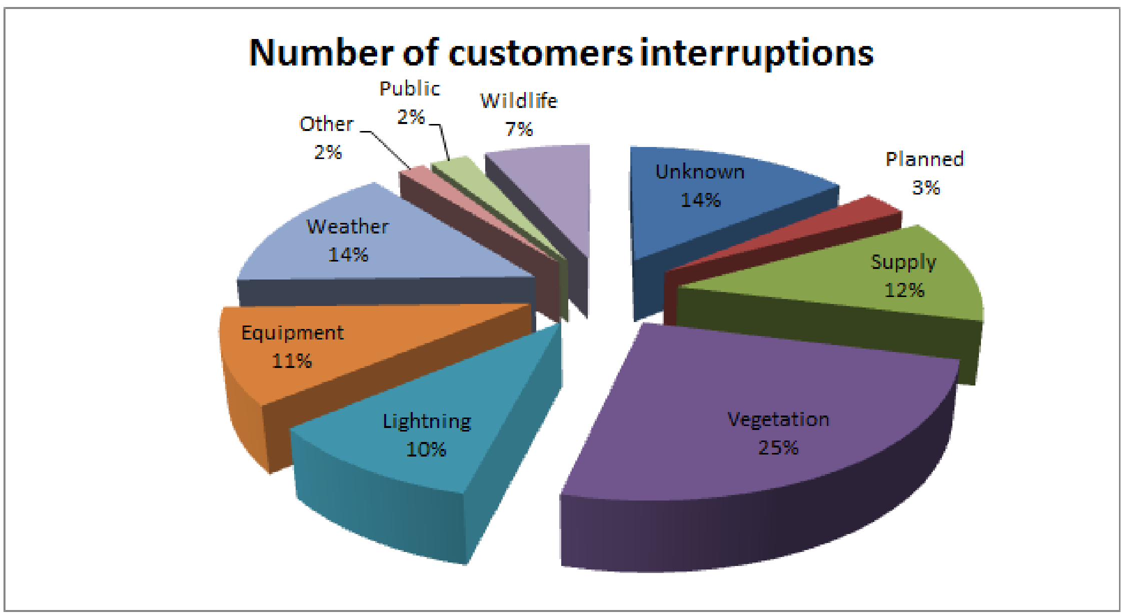

Figure 3-7 Affected customers percentage per cause, CNP

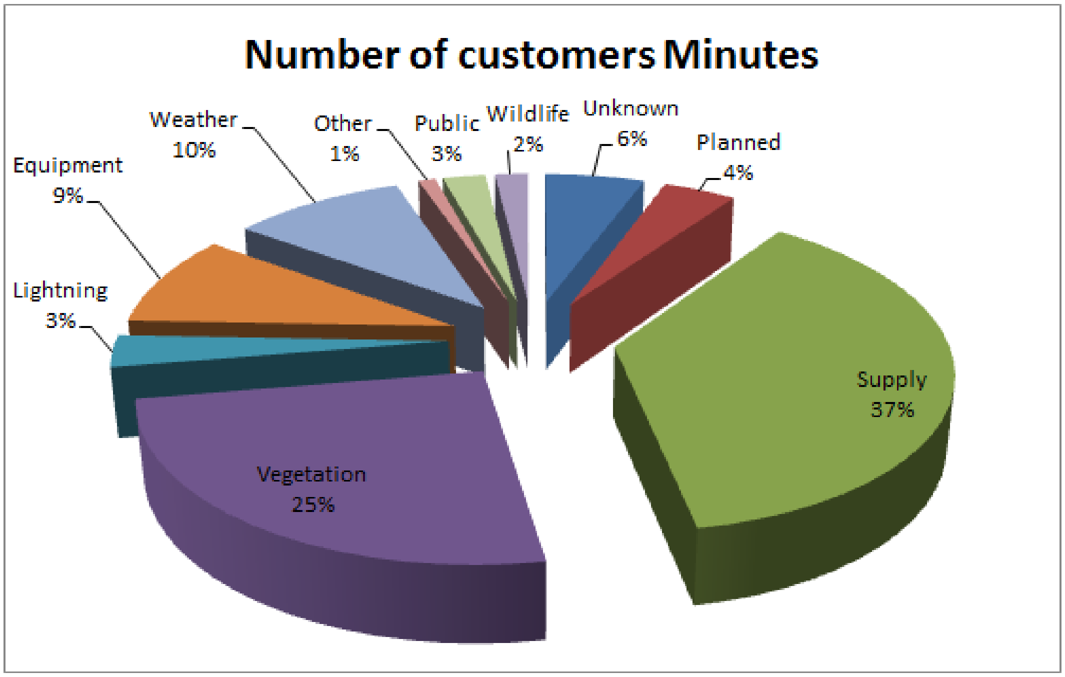

Figure 3-8 Interruption duration percentage per cause, CNP

3.4 Outage Causes Classification for PCH

The available outage data for PCH are classified according to causes. The total numbers of customer suffered from interruptions as well as the total number of customer interruption durations due to all causes are determined for cause separately. The results of the classification are presented in Table 3-6, Figure 3-9, and Figure 3-10.

Table 3-6 PCH outage causes classification

Cause	Sum of Customers affected	Sum of Customers interruption duration (Minutes)
Equipment	195947	4519976
Lightning	102419	427370
Planned	20451	8900034
Power supply	110282	8414912
Public	16409	66290
Vegetation	76552	3156013
Weather (other than lightning)	161022	1155965
Wildlife	38787	75630
Unknown	366016	837018
Other	5578	321394.07

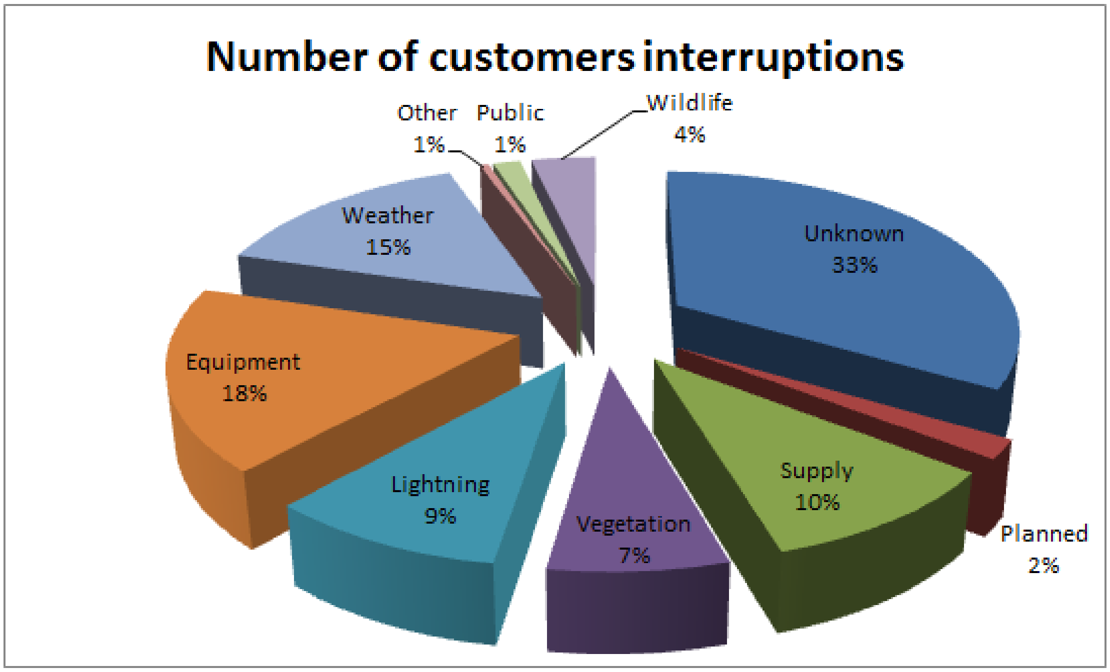

Figure 3-9 Affected customers percentage per cause, PCH

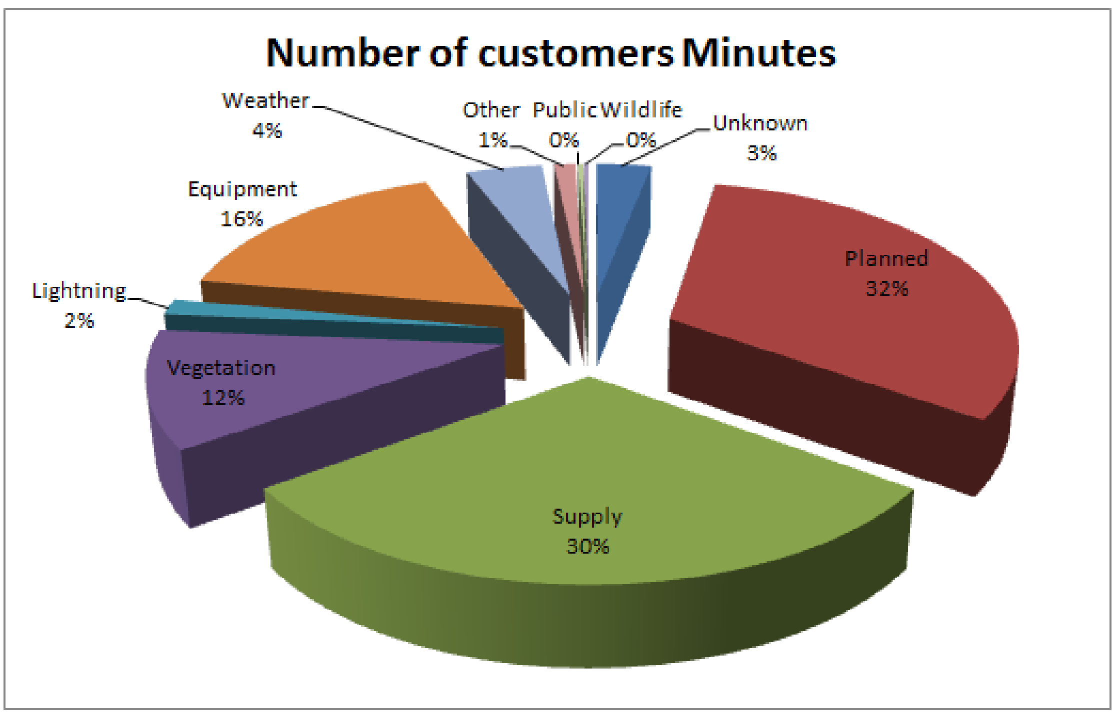

Figure 3-10 Interruption duration percentage per cause, PCH

3.5 Substations Outage Data Classification for CNP

The outage data is classified for each substation separately; The outage ranking of substations is summarized in Table 3-7, while the customers interrupted per cause and the interruption durations are presented in Table B-1 and Table B-2 in appendix B.

Table 3-7 Substation ranking, CNP

Substations	Sum of customers affected	Ranking based on customer affected	Sum of interruption durations (Min)	Ranking based on interruption durations
Station 11	19986	7	1780951	5
Station 12	109056	5	4575962	4
Station 13	969	8	100620	8
Station 15	35437	6	1030322	6
Station 17	**558581**	**1**	**15819594**	**1**
Station 18	**525628**	**2**	**11298516**	**2**
Station 19	**324431**	**3**	**7723338**	**3**
Hydro One Murray HONI	189788	4	458099	7

The chronological outage data classifications are presented for each substation separately in the following subsections. Tables B-3 to B-18 are introducing the affected number of customers and interruption durations for each substation classified chronologically and based on outage causes.

3.6 Substations Outage Data Classification for PCH

The outage data for PCH is classified for each substation separately; the outage ranking of substations is summarized in Table 6-8. The customers interrupted per cause are presented in Table B-19, while the interruption durations are presented in Table B-20. The chronological outage data classifications are presented for each substation separately in the following subsections. Tables B-21 to B-40 are introducing the affected number of customers and the interruption durations for each substation classified chronologically and based on outage causes.

Table 3-8 Substation ranking, PCH

Substations	Sum of customers affected	Ranking based on customer affected	Sum of interruption durations (Min)	Ranking based on interruption durations
Killally	2524	8	277892	7
Pt Colborne	**1238297**	**1**	**18760277**	**1**
Catharine	3145	7	270473	8
Jefferson	**31584**	**3**	**10349901**	**2**
Fielden	27104	4	1148835	4
Barrick	8699	5	696568	5
Sherkston	6085	6	489476	6
Welland Hydro	517	9	13513	9
Niagara Falls Hydro	8	10	0.27	10
Hydro One	118818	2	1510248	3

3.7 Major outage causes identification for CNP

The major outage causes for each substation are identified for each substation of CNP and presented in Table 3-9 from the perspective of the number of customers affected and in Table 3-10 from the interruption duration point of view.

Table 3-9 Substation major outage causes, customers affected, CNP

Substations	First major cause	Second major cause	Third major cause	Fourth major cause
Station 11	Supply	---	---	---
Station 12	Weather	Vegetation	Equipment	planned
Station 13	Public	planned	Weather	---
Station 15	Vegetation	Weather	Equipment	Supply
Station 17	**Vegetation**	**Weather**	**Lightning**	**Equipment**
Station 18	**Vegetation**	**Equipment**	**Lightning**	**Wildlife**
Station 19	**Vegetation**	**Weather**	**Lightning**	**Wildlife**
Hydro One Murray	Supply	---	---	---

Table 3-10 Substation major outage causes, interruption duration, CNP

Substations	First major cause	Second major cause	Third major cause	Fourth major cause
Station 11	Supply	---	---	---
Station 12	Supply	Vegetation	Equipment	Weather
Station 13	Public	planned	Weather	---
Station 15	Supply	Equipment	Vegetation	Weather
Station 17	**Vegetation**	**Supply**	**Weather**	**Equipment**
Station 18	**Supply**	**Vegetation**	**Equipment**	**Weather**
Station 19	**Vegetation**	**Supply**	**Weather**	**Equipment**
Hydro One Murray	Supply	---	---	---

3.8 Major outage causes identification for PCH

The major outage causes for each substation are identified for each substation of PCH and presented in Table 3-11 from the perspective of the number of customers affected and in Table 3-12 from the interruption duration point of view.

Table 3-11 Substation major outage causes, customers affected, PCH

Substations	First major cause	Second major cause	Third major cause	Fourth major cause
Killally	Lightning	Equipment	planned	Vegetation
Pt Colborne	**Equipment**	**Weather**	**Lightning**	**Vegetation**
Catharine	Public	Vegetation	Equipment	planned
Jefferson	**Vegetation**	**Equipment**	**Wildlife**	**Supply**
Fielden	Equipment	Vegetation	Lightning	Weather
Barrick	Equipment	Supply	Lightning	planned
Sherkston	Vegetation	Weather	planned	Equipment
Welland Hydro	Vegetation	planned	Equipment	---
Niagara Falls Hydro	---	---	---	---
Hydro One	Supply	---	**---**	**---**

Table 3-12 Substation major outage causes, interruption duration, PCH

Substations	First major cause	Second major cause	Third major cause	Fourth major cause
Killally	Lightning	Equipment	planned	Vegetation
Pt Colborne	**Supply**	**Equipment**	**Vegetation**	**Weather**
Catharine	Vegetation	Public	planned	Equipment
Jefferson	**planned**	**Vegetation**	**Supply**	**Lightning**
Fielden	Equipment	Lightning	Vegetation	Weather
Barrick	Supply	Equipment	Vegetation	Planned
Sherkston	Vegetation	planned	Weather	Equipment
Welland Hydro	Vegetation	planned	Equipment	---
Niagara Falls Hydro	---	---	---	---
Hydro One	Supply	---	---	---

3.9 Feeders Outage Data Classification

The outage data for CNPI (CNP and PCH) is classified for each feeder separately; the complete outage customers affected and interruption minutes for all feeders are summarized in Table B-41 and Table B-42 respectively. The ranking of the worst feeders based on the affected customers and interruption minutes are presented in Tables 3-13 and 3-14 respectively.

Table 3-13 Feeders ranking based on Customers affected

Ranking based on customer affected	Feeder Name	Sum of customers affected
1	43M10	321034
2	43M11	285484
3	17L67	261841
4	43M9	198076
5	1923	197568
6	43M12	194294
7	18L8	166880
8	Station 11	143844
9	18L10	137447
10	18L5	117010

Table 3-14 Feeders Ranking Based on Interruption Minutes

Ranking based on Interruption Minutes	Feeder Name	Sum of Customers Interruption Minutes
1	17L67	5878911
2	43M10	4863508
3	43M9	4717737
4	1923	3940653
5	18L10	3276438
6	67RT3	3091653
7	1911	2325290
8	18L8	2319531
9	43M11	2227147
10	18L5	2040186

4 Major Causes and Recommendations

The outage study showed the greatest proportion of the customers affected and Interruption Duration occurs at the five main substations (i.e., **Pt Colborne** , **Station 17, Station 18, Station 19, and Jefferson**). The exact ratio of the affected customers at these substations represents 83.68% of the total customers affected. In addition, the exact ratio of the interruption durations at these substations represents 83.81 % of the total number of interruption durations. Table 4-1 shows the outage data for those five substations.

Table 4-1 Outage Data for the Five Main Substations of CNPI

Substations	Sum of customers affected	Sum of interruption durations (Min)
Pt Colborne	1238297	18760277
Station 17	558581	15819594
Station 18	525628	11298516
Jefferson	31584	10349901
Station 19	324431	7723338

The detailed outage study for the different feeders within CNPI showed that out of the total of 127 feeders, only five feeders (i.e., 17L67, 43M10, 43M9, 1923 and 18L10) are responsible for more than 34% of the total outages as presented in Table 4-2.

Table 4-2 Outage Data for the Five Main Feeders of CNPI

Feeder	Sum of customers affected	Sum of interruption durations (Min)	Substations
17L67	261841	5878911	Station 17
43M10	321034	4863508	Pt Colborne
43M9	198076	4717737	Pt Colborne
1923	197568	3940653	Station 19
18L10	137447	3276438	Station 18

Moreover, the results, presented in section 3, show that the major causes of the outages for the five main substations are vegetation, power supply, weather, and equipment as presented in Table 4-3. The management enhancement of the controllable causes would positively affect the reliability indices. Therefore, the major events and recommendations for controlling the vegetation outages and the equipment failures are further investigated. Moreover, recommendations for decreasing the outage durations are discussed.

Table 4-3 Major Outage Causes for the Five Main Substation

Substations	First major cause	Second major cause	Third major cause	Fourth major cause
Pt Colborne	Supply	Equipment	Vegetation	Weather
Station 17	Vegetation	Supply	Weather	Equipment
Station 18	Supply	Vegetation	Equipment	Weather
Jefferson	Vegetation	Equipment	Wildlife	Supply
Station 19	Vegetation	Supply	Weather	Equipment

4.1 Vegetation Management Recommendation

The current vegetation management plan divides the whole system into three zones as shown in Figures 4-1 and 4-2, and the tree trimming and grubbing are performed for one zone every year; so each zone will be re-visited every three years.

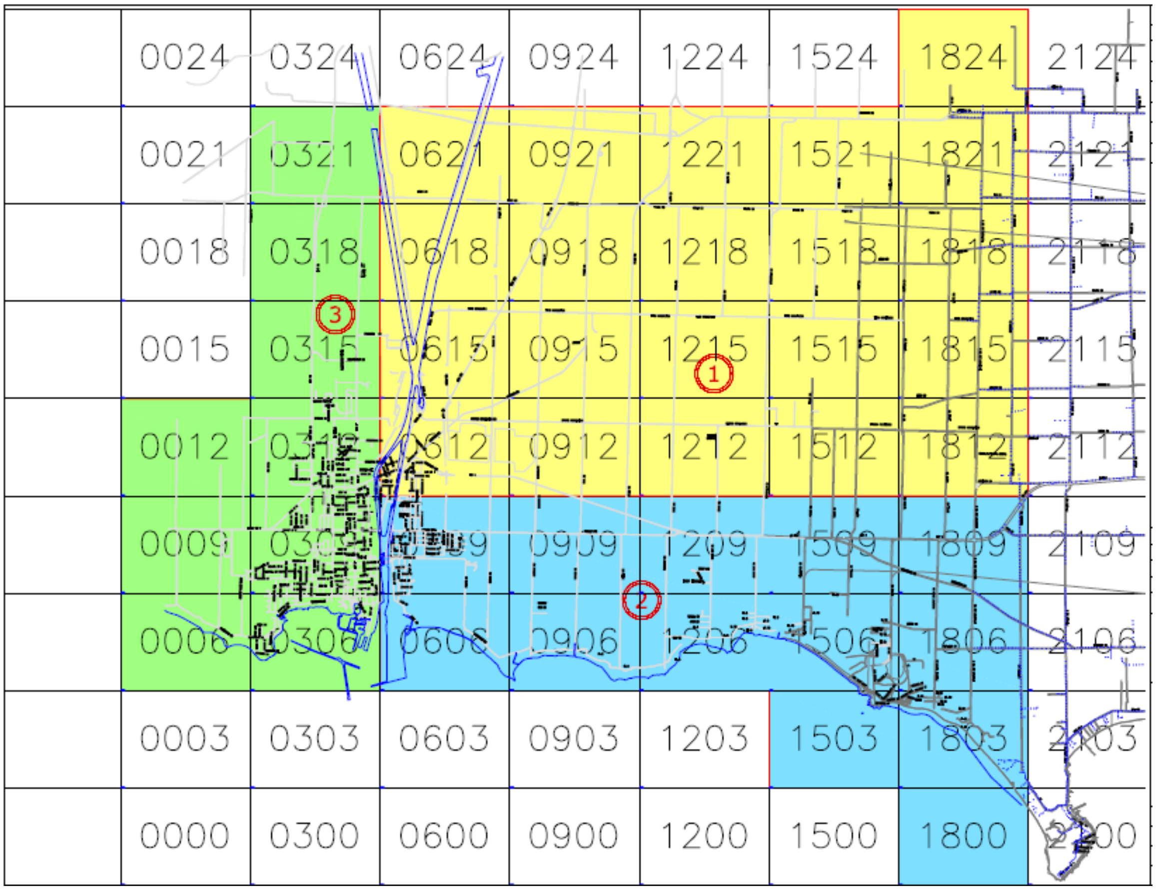

Figure 4-1 Vegetation Management Zones for FORT ERIE Town

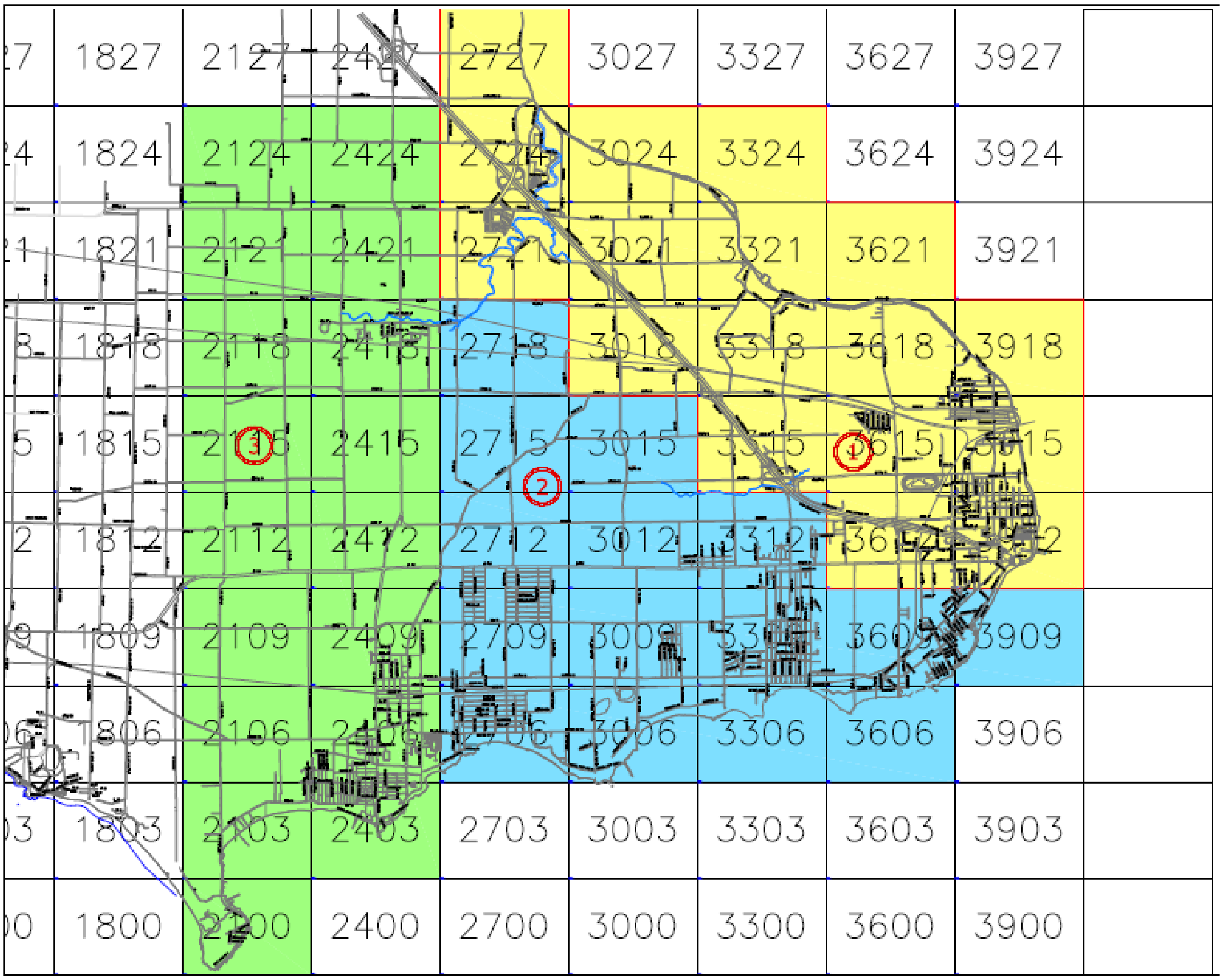

Figure 4-2 Vegetation Management Zones for Port Colborne Town

This vegetation management plan is reflected on the outage data for the main substations; as shown in Figures 4-3 to 4-6. It is clear from the figures that the outages caused by trees are following a cycle similar to the vegetation management plan cycle; i.e. outages decrease in the year following the vegetation management, and then increase in the successive year.

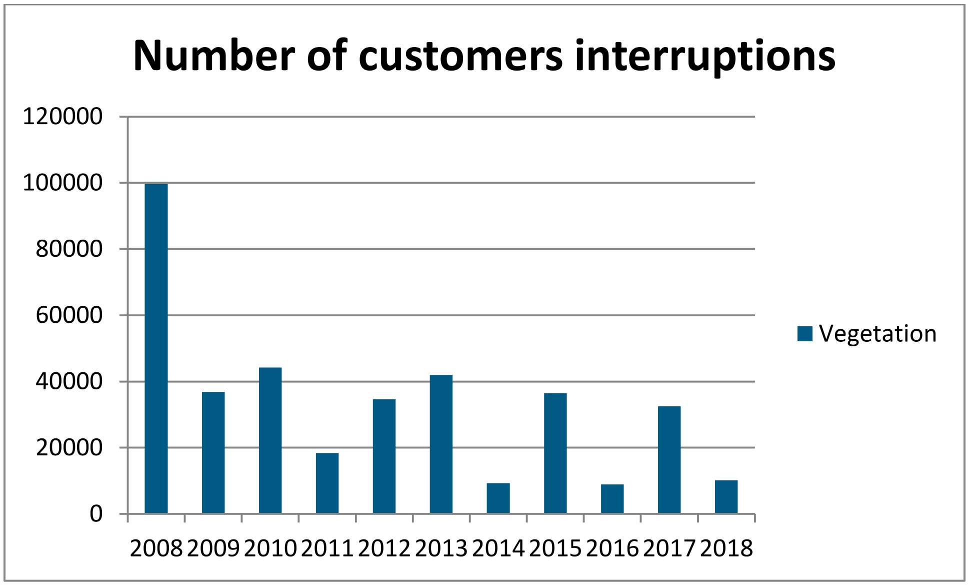

Figure 4-3 Vegetation interruptions for Pt Colborne

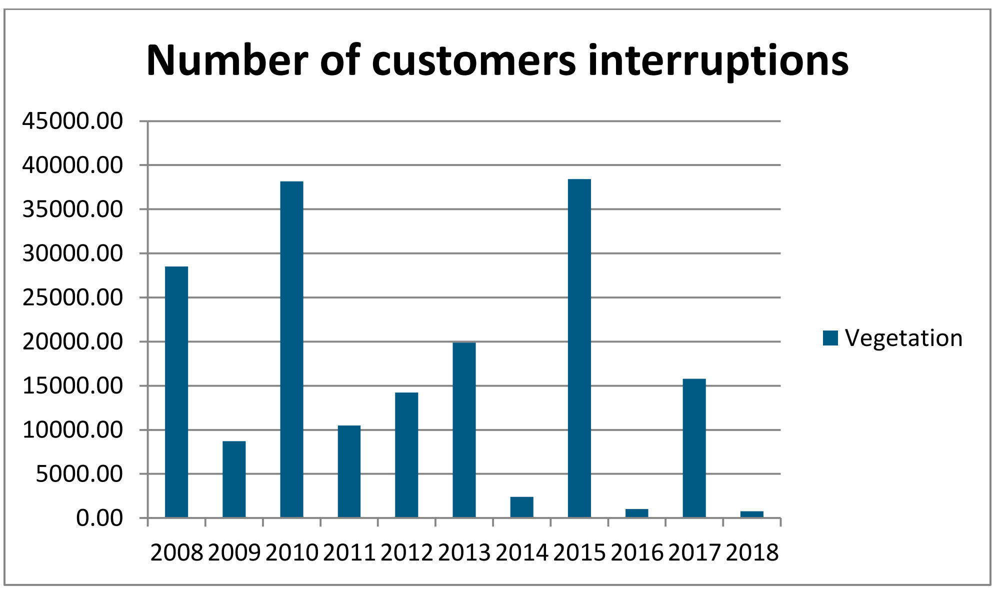

Figure 4-4 Vegetation interruptions for Station 17

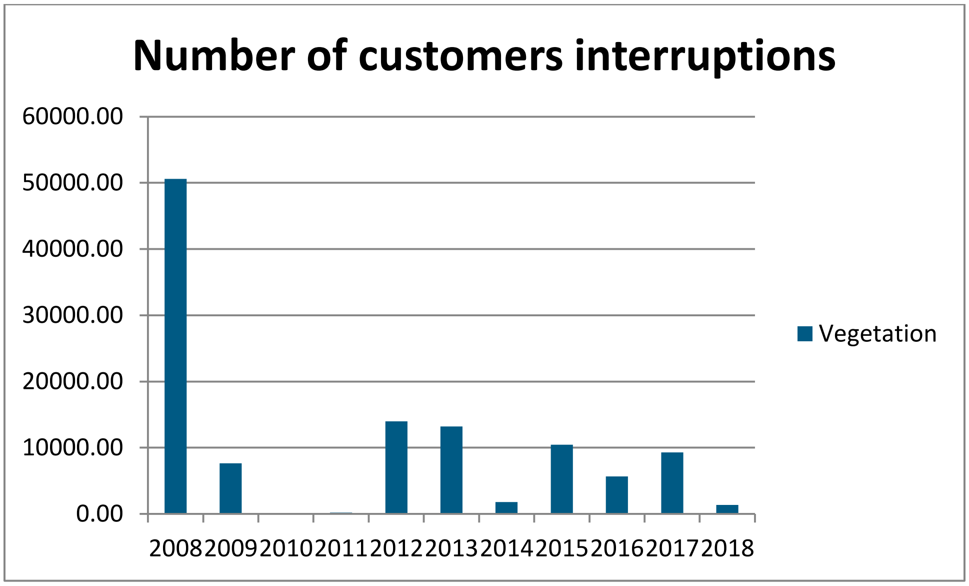

Figure 4-5 Vegetation interruptions for Station 18

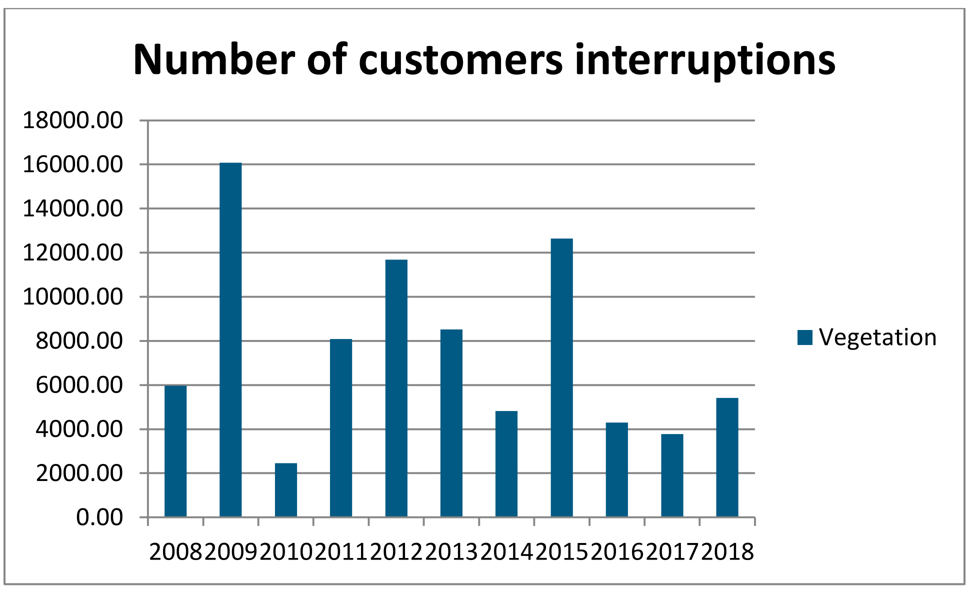

Figure 4-6 Vegetation interruptions for Station 19

Recommendation: the recommendation to reduce the primary cause of outages (i.e., Vegetation), is to revisit the vegetation management plan, especially for selected areas that causing more outages than others. Table 4-4 presents the areas of the main five substations; those areas should have more frequent vegetation management cycles (i.e., every year).

Table 4-4 Areas of the Five Main Substation

Substations	Covering Areas
Pt Colborne	Service areas of feeders: 43M9, M9RT3, RCM9-1, M9RT16, 43M10, 43M11, M10RT6, M11RT10, M12RT17, 43M12, M12RT1, M12RT4, M12RT5, M12RT7, M12RT8, M12RT11, M12RT12, M12RT14
Station 17	Service areas of feeders: 17L5, 17L8 17L9, 17L67, 8RT1, 9RT1, 9RT3, 67RT1, 67RT3, STATION 13, STATION 19, RC17L8-1, 67RT2, 67RT4, 8RT2
Station 18	Service areas of feeders: 18L5, 18L8, 18L10, 18L11, 5RT7, 5RT1, 5RT2, 5RT3, 5RT6, 10RT1, 10RT2, 10RT3, 11RT1, 10RT4, 10RT5, RC18L10-2
Jefferson	Service areas of feeders: RCM10-1, JF1, JF2, JF3
Station 19	Service areas of feeders: 1911, 1912, 1913, 1921, 1922, 1923, RC1921-1

4.2 Equipment Maintenance Recommendation

Another major cause for the outages in CNPI is due to Equipment failure, which can be reduced by improving maintenance, inspection, and selective replacement strategy. The current general equipment maintenance schedule is every five up to eight years as shown in Tables 4-5 and 4-6. This equipment maintenance schedule impacted the number of outages caused by equipment failure as shown in Table 4-7; the table show great enhancement in the equipment failure outages for years 2016 and 2017 for feeder 17L67 compared to 2015 (i.e. feeder maintenance year).

Table 4-5 Maintenance Schedule for Fort Erie

Substations	Feeders	Schedule Dates for Maintenance
17	17L5	2012, 2016, 2024
17	17L8	2013, 2017, 2025
17	17L9	2014, 2018, 2026
17	17L67	2015, 2019, 2027
18	18L5	2012, 2020, 2028
18	18L8	2013, 2021, 2029
18	18L10	2014, 2022, 2030
18	18L11	2015, 2023, 2031

Table 4-6 Maintenance Schedule for Port Colborne

Substations	Feeders	Schedule Dates for Maintenance
Port Colborne TS	43M9	2012, 2015, 2020
Port Colborne TS	43M10	2013, 2016, 2021
Port Colborne TS	43M11	2014, 2017, 2022
Port Colborne TS	43M12	2015, 2018, 2023
Port Colborne TS	43M13	2016, 2019, 2024

Table 4-7 Outages due to Equipment Failure, Feeder 17L67

Year	Affected Customers	Sum of Interruption Durations
2015	15061	304231
2016	5774	519
2017	8	550

Recommendation: the recommendation to reduce the equipment outages is to revisit the feeder maintenance plan for the main feeders that causing more outages than others. Table 4-8 summarizes the main feeders that causing outages and the corresponding suggested equipment maintenance schedule (i.e. every two years).

Table 4-8 Feeder Maintenance Recommended Schedule

Substations	Feeders	Current Maintenance Schedule	Recommended Maintenance Schedule
Station 17	17L67	2015, 2019, 2027	2015, 2019, 2021, 2023, 2025
Pt Colborne	43M10	2013, 2016, 2021	2013, 2016, 2020, 2022, 2024
Pt Colborne	43M9	2015, 2019, 2027	2014, 2017, 2019, 2021, 2023, 2025
Station 19	1923	2015, 2018, 2023	2015, 2018, 2020, 2022, 2024
Station 18	18L10	2014, 2022, 2030	2014, 2019, 2021, 2023, 2025

4.3 Feeder Automation Recommendation

The current protection scheme for CNPI declares that the tripping switches are manually reset after any trip event. This action extend the fault outage duration until the crew manually isolates the faulted area and restores power to the unaffected segments of the feeder. One important recommendation to decrease the outage duration is the Feeder Automation (FA) for some selected feeders experiencing extended outages.

For FA implementation, automated switches, software and communications devices are to be installed on the selected trunk feeders. These devices improve the reliability by reducing the impact of trunk-related outages. The FA system utilizes remote switching technology and specialized software loaded in each switch remote terminal unit (RTU) to reduce the duration of outages by automatically isolating the faulted area and restoring the power to the unaffected segments of the feeder within one minute.

FA is an effective solution to mitigate the impact of outages on the main portions of the feeder (i.e., the trunk). When a fault occurs, FA works by dividing the feeder into segments, and then uses networked and automated switches to perform an algorithmic review and switching to assess the outage and automatically restore power to any unaffected feeders and the customers they serve. With FA technology, this entire operation can be done in less than one minute. In comparison, manual operation of switches by line crews typically takes between two and four hours to achieve the same restoration of power to unaffected customers. Thus, FA can limit the number of customers impacted by an outage on a trunk feeder and it dramatically improves restoration times. The feeders presented in Table 4-9 represent the worst feeders experiencing the largest outage durations. Automation of these feeders would greatly enhance the system reliability.

Table 4-9 Candidate feeders for Feeder Automation

Feeder name	Number of affected customers	Interruption duration (Minutes)
17L67	261841	5878911
43M10	321034	4863508
43M9	198076	4717737
1923	197568	3940653
18L10	137447	3276438

The cost estimate for the Feeder Automation option is presented in Table 4-10. The switches to be automated are the main switch, the sectionalizers, and the tie switches. The average feeder automation cost (installation and upgrading costs per feeder) is C$ 300k-400 k.

Table 4-10 Cost Estimates of Feeder Automation

Hardware	Cost ($)	Cost with Overheads ($)
Switch for Overhead Distribution including the SCADA/software and communication upgrades	61,200	70,380

Appendix A

Scorecards for CNPI

Scorecard - Canadian Niagara Power Inc. 9/29/2016

Performance Outcomes	Performance Categories	Measures		2011	2012	2013	2014	2015	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		97.70%	95.70%	93.10%	96.00%	94.40%	↓	90.00%	
		Scheduled Appointments Met On Time		100.00%	100.00%	100.00%	100.00%	100.00%	→	90.00%	
		Telephone Calls Answered On Time		83.40%	84.60%	82.60%	78.20%	76.10%	↓	65.00%	
	Customer Satisfaction	First Contact Resolution					99.9%	99.80%			
		Billing Accuracy					99.92%	99.91%	↓	98.00%	
		Customer Satisfaction Survey Results				80.84%	79.59%	94%			
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						81.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	NI	→		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	1	0	→		0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.978	0.000	→		0.137
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		1.82	1.89	3.22	1.95	2.36	↑		1.96
		Average Number of Times that Power to a Customer is Interrupted [2]		1.63	2.21	2.72	2.07	2.78	↑		1.98
	Asset Management	Distribution System Plan Implementation Progress					Completed	Completed			
	Cost Control	Efficiency Assessment			4	4	4	4			
		Total Cost per Customer [3]		$727	$679	$726	$749	$778			
		Total Cost per Km of Line [3]		$20,204	$18,790	$20,275	$21,202	$21,726			
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]						12.30%			28.48 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time				0.00%					
		New Micro-embedded Generation Facilities Connected On Time				97.78%	95.65%	100.00%	↑	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.65	0.33	0.34	0.33	0.35			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		2.97	2.53	2.30	2.02	1.72			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	8.01%	8.01%	8.93%	8.93%	8.93%			
			Achieved	7.21%	9.42%	6.71%	8.31%	10.00%			

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

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

Figure C-2 CNPI Scorecard

Appendix B

CNPI Complete Outage Data Classification for Substations and Feeders

B.1 Complete outage data classification for CNP

Table B-1 Affected customer per substation, CNP

	Number of affected customers									
Substation	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
Station 11	0.00	0.00	19986	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Station 12	16639	4637	3828	21973	3528	12295	31466	11055	2951	684
Station 13	0.00	106	0.00	0.00	0.00	0.00	1.00	0.00	862	0.00
Station 15	839	1411	1316	15086	585	4432	11685	34	21	28
Station 17	58155	15029	22290	178424	59393	53445	122596	8704	17886	22659
Station 18	116286	3680	33205	114282	64591	77179	40375	5434	11794	58802
Station 19	40197	7533	3288	83766	51653	35982	59512	1161	10686	30653
Hydro One Murray	0.00	0.00	189788	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table B-2 Interruption durations per substation, CNP

	Number of affected customers									
Substation	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
Station 11	0.00	0.00	1780951	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Station 12	248388	129369	1894875	800840	19853	596342	444972	284804	123774	32741
Station 13	0.00	374	0.00	0.00	0.00	0.00	31	0.00	100215	0.00
Station 15	1418	14371	637843	103305	6431	237673	23806	2010	2396	1066
Station 17	1060983	919864	4234472	5025666	594157	1660947	1831200	69931	345462	76907
Station 18	775898	349168	4592972	1805133	707514	1491322	759898	11362	271565	533679
Station 19	261703	295300	1543606	2749457	269265	721671	1320558	3524	438064	120186
Hydro One Murray HONI	0.00	0.00	458099	0.00	0.00	0.00	0.00	0.00	0.00	0.00

a) Station 11

Table B-3 Affected customer for Station 11, CNP

	Number of affected customers									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2009	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2012	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2013	0.00	0.00	3689	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	16297	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table B-4 Affected customer for Station 11, CNP

	Interruption duration (Minutes)									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2009	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2012	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2013	0.00	0.00	221340	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	1559611	0.00	0.00	0.00	0.00	0.00	0.00	0.00

b) Station 12

Table B-5 Affected customer for Station 12, CNP

	Number of affected customers									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	652.00	63.00	0.00	11170	238.00	338.00	0.00	17.00	2.00	0.00
2009	625.00	1880.00	0.00	945.00	7.00	870.00	1746.00	1335.00	1.00	1.00
2010	587.00	156.00	0.00	293.00	0.00	571.00	2455.00	5677.00	82.00	0.00
2011	1875.00	109.00	0.00	267.00	42.00	1525.00	95.00	1287.00	34.00	0.00
2012	91.00	250.00	3828	1269	0.00	59.00	713.00	591.00	684.00	541.00
2013	2205.00	1173.00	0.00	112.00	212.00	2143.00	1944.00	40.00	726.00	30.00
2014	323.00	332.00	0.00	313.00	613.00	854.00	5756.00	0.00	18.00	1.00
2015	2109.00	279.00	0.00	2328	1671	189.00	4235.00	1414.00	7.00	12.00
2016	2195.00	224.00	0.00	61.00	745.00	857.00	614.00	1.00	1300	6.00
2017	4547.00	132.00	0.00	5102	0.00	2085.00	6498.00	693.00	86.00	93.00

2018	1430.00	39.00	0.00	113.00	0.00	2804.00	7410.00	0.00	11.00	0.00

Table B-6 Interruption duration for Station 12, CNP

	Interruption duration (Minutes)									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	193.93	6850.00	0.00	165820	307.67	21906.00	0.00	1360.00	525.00	0.00
2009	63059.00	2789.05	0.00	42785.25	480.00	13428.25	14674.30	93756.00	205.00	30.00
2010	146.75	5401.00	0.00	17715.37	0.00	29765.60	4648.50	18000.63	5114.00	0.00
2011	17674.08	4920.00	0.00	36894.00	3925	117129.38	108.25	4708.90	1610.00	0.00
2012	6121.30	9878.00	189487	24771.40	0.00	1189.00	30166.25	21494.45	17585.33	23841
2013	1589.70	19096.00	0.00	31020.00	1566	153253.77	44085.00	2960.00	760.75	1350
2014	5886.25	34261.00	0.00	18655.00	2722	21439.22	159240	0.00	900.00	65.00
2015	13028.00	17550.00	0.00	44335.80	1902	8139.00	149630	142389	720.00	1080
2016	34392.67	14372.00	0.00	10390.00	8949	89766.78	39879.30	30.00	85702.78	330.00
2017	78751.32	9152.00	0.00	390946.9	0.00	75791.67	1645.77	104.60	10630.00	6045.0
2018	27545.17	5100.00	0.00	17507.00	0.00	64534.20	894.40	0.00	22.00	0.00

c) Station 13

Table B-7 Affected customer for Station 13, CNP

	Number of affected customers									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	0.00	106.00	0.00	0.00	0.00	0.00	1.00	0.00	862.00	0.00
2009	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2012	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2013	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table B-8 Interruption duration for Station 13, CNP

	Interruption duration (Minutes)									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	0.00	374.00	0.00	0.00	0.00	0.00	31.00	0.00	100215	0.00
2009	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2012	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2013	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

d) Station 15

Table B-9 Affected customer for Station 15, CNP

	Number of affected customers									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	0.00	0.00	0.00	3387	0.00	9.00	0.00	0.00	0.00	0.00
2009	0.00	0.00	0.00	3444	60.00	12.00	6755.00	0.00	0.00	0.00
2010	0.00	0.00	0.00	3243	12.00	46.00	806.00	0.00	17.00	0.00
2011	0.00	31.00	0.00	0.00	59.00	1087.00	1668.00	33.00	1.00	0.00
2012	820.00	62.00	1316.00	807.00	0.00	17.00	0.00	0.00	1.00	0.00
2013	0.00	1143.00	0.00	460.00	454.00	2776.00	0.00	0.00	0.00	27.00
2014	2.00	6.00	0.00	3.00	0.00	31.00	0.00	0.00	2.00	1.00
2015	17.00	168.00	0.00	614.00	0.00	449.00	2456.00	0.00	0.00	0.00
2016	0.00	1.00	0.00	3128	0.00	5.00	0.00	1.00	0.00	0.00
2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table B-10 Interruption duration for Station 15, CNP

	Interruption duration (Minutes)									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	0.00	0.00	0.00	18621	0.00	514.00	0.00	0.00	0.00	0.00
2009	0.00	0.00	0.00	47962	2700	818.00	23041.93	0.00	0.00	0.00
2010	0.00	0.00	0.00	2427	1248	1111.00	214.93	0.00	2040.00	0.00
2011	0.00	2040.00	0.00	0.00	2468	54983.43	417.00	1935.00	241.00	0.00
2012	411.50	4630.00	637843	11975	0.00	898.00	0.00	0.00	15.00	0.00
2013	0.00	2816.65	0.00	16223	15.13	162556.68	0.00	0.00	0.00	1025
2014	274.00	265.00	0.00	150.00	0.00	1814.00	0.00	0.00	100.00	41.00
2015	733.00	3259.80	0.00	5352	0.00	14880.60	133.03	0.00	0.00	0.00
2016	0.00	1360.00	0.00	593.02	0.00	98.00	0.00	75.00	0.00	0.00
2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

e) Station 17

Table B-11 Affected customer for Station 17, CNP

	Number of affected customers									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	8877.00	5156.00	0.00	28515	13252	3157.00	35.00	2606.00	47.00	5856
2009	2388.00	2270.00	0.00	8732	5694	8102.00	7315.00	9.00	3.00	18.00
2010	3869.00	268.00	0.00	38155	1008	4432.00	4215.00	607.00	1234.00	31.00
2011	3812.00	282.00	0.00	10507	9884	3724.00	13260.00	22.00	17.00	231.00
2012	3886.00	867.00	11034.00	14220	1.00	1804.00	4183.00	334.00	2853.00	517.00
2013	2782.00	1303.00	3508.00	19898	20274	865.00	30086.00	1.00	1676.00	2.00

2014	1083.00	1186.00	0.00	2410	1015	3207.00	1749.00	5.00	5454.00	5531
2015	13808.00	1161.00	0.00	38406	66.00	17798.00	28662.00	5000.00	3.00	10011
2016	14848.00	1856.00	0.00	1019	6933	5916.00	0.00	55.00	978.00	415.00
2017	2800.00	578.00	7748.00	15797	1266	4062.00	9865.00	0.00	5187.00	9.00
2018	2.00	102.00	0.00	765.00	0.00	378.00	23226.00	65.00	434.00	38.00

Table B-12 Interruption duration for Station 17, CNP

	Interruption duration (Minutes)									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	3557.87	85842.07	0.00	1318077	43398	69558.20	3265	31089.40	5769.80	1127
2009	18139.05	22651.52	0.00	580934	349121	280779.95	136441	426.00	110.00	1103
2010	511.02	28717.00	0.00	350908	5056	153419.77	26788	7197.35	1255.40	2366
2011	7296.98	12625.67	0.00	306722	26979	89601.27	46800	705.00	2153.00	24566
2012	243350.50	45069.00	2652822	262506	75.00	40242.87	83351	11767.42	71414.55	4140
2013	45585.42	75705.97	182416	157751	12334	521152.95	204481	10.00	1594.53	85.00
2014	134055.25	33055.38	0.00	94225.77	48674	60594.67	130961	120.00	4936.23	4891
2015	11770.33	91150.00	0.00	512970	3940	343871.92	32159	10166.67	128.00	34837
2016	558645.52	401710	0.00	50938.00	59517	8500.72	0.00	7800.00	136001	728.85
2017	37982.85	114340	1399234	1207595	45061	33097.93	1359	0.00	98431.30	445.00
2018	89.00	8998.00	0.00	183035	0.00	60127.00	1165592	650.00	23668.02	2615

f) Station 18

Table B-13 Affected customer for Station 18, CNP

	Number of affected customers									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	50571.00	280.00	0.00	50602	17072	6713.00	78.00	23.00	5691.00	4206
2009	7599.00	798.00	0.00	7642	11799	317.00	11515.00	0.00	0.00	2153
2010	5542.00	26.00	0.00	60.00	4959	6426.00	622.00	2731.00	0.00	6790
2011	1994.00	252.00	7761.00	196.00	4157	8631.00	1806.00	4.00	596.00	2170
2012	2122.00	461.00	20728.00	13978	0.00	6712.00	2316.00	9.00	2534.00	20992
2013	15074.00	278.00	0.00	13199	7960	25147.00	35.00	0.00	1.00	12183
2014	1102.00	578.00	0.00	1796	10067	6400.00	2964.00	0.00	20.00	2.00
2015	15370.00	190.00	0.00	10475	2643	8910.00	10897.00	2486.00	2.00	9725
2016	4903.00	695.00	0.00	5665	484.00	5352.00	23.00	0.00	1801.00	498.00
2017	8880.00	98.00	4716.00	9280	5450	1892.00	386.00	181.00	1149.00	83.00
2018	3129.00	24.00	0.00	1389	0.00	679.00	9733.00	0.00	0.00	0.00

Table B-14 Interruption duration for Station 18, CNP

	Interruption duration (Minutes)									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	345371.53	20629.00	0.00	581782	9203	35030.10	3540.00	1454.00	128788	4927
2009	731.53	124600.7	0.00	111562	141727	7815.00	239208.9	0.00	0.00	2884
2010	271.72	2715.00	0.00	4484	6455	135153.30	20.73	4365.97	0.00	7929.2
2011	996.60	19534.00	193472.7	8846	856.73	664246.17	38410.42	240.00	49356.65	4986.4

2012	106.10	26487.10	3257523	150756	0.00	76901.30	37629.13	1820.00	126.55	18788
2013	6217.13	25779.00	0.00	472289	219893	166386.10	2100.00	0.00	60.00	269793
2014	165.30	12157.27	0.00	79946	20311	18383.78	185.87	0.00	2100.00	189.00
2015	15952.02	22499.77	0.00	74822	6808.5	122276.35	403945.5	2839.67	65.00	166864
2016	10198.73	65994.47	0.00	50390	42200	166165.92	2369.00	0.00	8296.55	51191
2017	394608.10	27224.00	1141976	207469	260057	86810.83	12.87	642.55	82772.32	6124.7
2018	1279.42	1548.00	0.00	62784	0.00	12154.08	32476.38	0.00	0.00	0.00

g) Station 19

Table B-15 Affected customer for Station 19, CNP

	Number of affected customers									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	3171.00	128.00	0.00	5966	1911	60.00	0.00	0.00	1.00	3.00
2009	4459.00	94.00	0.00	16086	10088	81.00	21317.00	1.00	21.00	38.00
2010	0.00	113.00	0.00	2459	746.00	33.00	742.00	0.00	842.00	3049
2011	2115.00	572.00	0.00	8092	4691	1637.00	3.00	1116.00	98.00	3531
2012	3005.00	177.00	3288.00	11685	0.00	690.00	6320.00	32.00	0.00	54.00
2013	2379.00	66.00	0.00	8514	1553	1971.00	2236.00	1.00	0.00	6642
2014	1610.00	6152.00	0.00	4825	11303	20483.00	8356.00	1.00	992.00	1117
2015	4964.00	55.00	0.00	12644	10144	1884.00	8956.00	0.00	0.00	11168
2016	8179.00	85.00	0.00	4300	11207	8938.00	260.00	0.00	1032.00	4977
2017	8502.00	60.00	0.00	3773	10.00	134.00	1302.00	0.00	7696.00	49.00
2018	1813.00	31.00	0.00	5422	0.00	71.00	10020.00	10.00	4.00	25.00

Table B-16 Interruption duration for Station 19, CNP

	Interruption duration (Minutes)									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	331.43	7310.00	0.00	135269	23936	4851.00	0.00	0.00	345.00	180.00
2009	1331.90	5299.00	0.00	811634	56369	6520.00	19909.83	15.00	1085.00	2665
2010	0.00	8100.00	0.00	5321.1	226.10	1370.00	37.10	0.00	257.05	5666.9
2011	884.93	24824.00	0.00	175464	4796.5	21472.93	105.00	1692.60	3271.00	6960.0
2012	1113.05	8547.00	1543606	103139	0.00	4569.57	12555.98	827.00	0.00	1807.0
2013	2491.82	2903.00	0.00	384457	3835.8	20259.83	395.70	150.00	0.00	50552
2014	3027.85	219232	0.00	82486	177408	352681.98	298734	240.00	91346.67	19480
2015	587.45	2465.00	0.00	276294	507.20	10858.08	91561.13	0.00	0.00	11757
2016	8035.93	4214.00	0.00	137011	665.30	280093.75	16400.17	0.00	584.12	17232
2017	187960.10	10178.00	0.00	322663	1520	15269.00	65.10	0.00	340977	2366
2018	55938.60	2228.00	0.00	315714	0.00	3725.00	880794	600.00	199.00	1518

h) Hydro One Murray HONI

Table B-17 Affected customer for Hydro One Murray HONI, CNP

	Number of affected customers									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife

2008	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2009	0.00	0.00	15655.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2010	0.00	0.00	31358.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2011	0.00	0.00	31319.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2012	0.00	0.00	63000.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2013	0.00	0.00	15862.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	32594.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table B-18 Interruption duration for Hydro One Murray HONI, CNP

	Interruption duration (Minutes)									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2009	0.00	0.00	260.92	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2010	0.00	0.00	345339.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2011	0.00	0.00	521.98	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2012	0.00	0.00	11287.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2013	0.00	0.00	2908.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	97782.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

B.2 Complete outage data classification for PCH

Table B-19 Affected customer per substation, PCH

	Number of affected customers									
Substation	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
Killally	540.00	306.00	0.00	169.00	844.00	500.00	77.00	12.00	23.00	53.00
Pt Colborne	452484.00	10094.00	69006.00	73564.00	166323.00	203288.00	179562.00	4827.00	28830.00	50319.00
Catharine	56.00	191.00	0.00	834.00	0.00	248.00	57.00	5.00	1718.00	36.00
Jefferson	4809.00	255.00	1312.00	14609.00	1272.00	6931.00	1028.00	5.00	48.00	1315.00
Fielden	1848.00	1431.00	0.00	5863.00	4468.00	9213.00	1978.00	2303.00	0.00	0.00
Barrick	2373.00	947.00	1441.00	723.00	1141.00	1978.00	1.00	17.00	23.00	55.00
Sherkston	832.00	606.00	0.00	2028.00	140.00	367.00	1934.00	177.00	1.00	0.00
Welland Hydro	0.00	10.00	0.00	499.00	0.00	8.00	0.00	0.00	0.00	0.00
Niagara Falls Hydro	8.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro One	0.00	0.00	118818.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table B-20 Interruption durations per substation, PCH

	Number of affected customers

Substation	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
Killally	11795.05	21315.00	0.00	14164.00	184948	34556.00	6805.00	412.00	2607.00	1290.0
Pt Colborne	1114177.03	528664.4	8289882	1630014	857319	4406112.22	1424169	243123	178889	87925
Catharine	4430.00	13946.00	0.00	141255	0.00	16295.00	7695.00	60.00	85724.00	1068
Jefferson	36117.18	8691850	172987	1138210	89713	85426.20	51013.68	350.00	12129.00	65.75
Fielden	1159.35	41533.95	0.00	209260.6	364322	411190.85	47279.40	74089.60	0.00	0.00
Barrick	4761.93	88110.00	276191.6	158850.0	57.05	160404.70	54.00	480.00	2209.00	5450.0
Sherkston	11760.47	53457.82	0.00	287963.1	20777	34988.15	61813.13	18701.13	15.00	0.00
Welland Hydro	0.00	888.00	0.00	12104.77	0.00	521.00	0.00	0.00	0.00	0.00
Niagara Falls Hydro	0.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro One	0.00	0.00	1510248	0.00	0.00	0.00	0.00	0.00	0.00	0.00

i. Killally

Table B-21 Affected customer for Killally, PCH

	Number of affected customers									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	361.00	106.00	0.00	52.00	50.00	27.00	0.00	11.00	0.00	0.00
2009	0.00	41.00	0.00	20.00	83.00	50.00	0.00	1.00	1.00	0.00
2010	0.00	12.00	0.00	0.00	0.00	34.00	30.00	0.00	18.00	0.00
2011	2.00	63.00	0.00	47.00	1.00	28.00	17.00	0.00	0.00	0.00
2012	0.00	3.00	0.00	50.00	0.00	63.00	0.00	0.00	0.00	0.00
2013	1.00	34.00	0.00	0.00	123.00	66.00	0.00	0.00	0.00	0.00
2014	0.00	2.00	0.00	0.00	547.00	25.00	0.00	0.00	3.00	0.00
2015	0.00	32.00	0.00	0.00	40.00	61.00	30.00	0.00	0.00	0.00
2016	1.00	6.00	0.00	0.00	0.00	97.00	0.00	0.00	1.00	48.00
2017	175.00	6.00	0.00	0.00	0.00	31.00	0.00	0.00	0.00	5.00
2018	0.00	1.00	0.00	0.00	0.00	18.00	0.00	0.00	0.00	0.00

Table B-2 Affected customer for Killally, PCH

	Interruption duration (Minutes)									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	18.05	8720.00	0.00	6144.00	12000.00	543.00	0.00	407.00	0.00	0.00
2009	0.00	1530.00	0.00	600.00	18675.00	3574.00	0.00	5.00	20.00	0.00
2010	0.00	1416.00	0.00	0.00	0.00	2330.00	3150.00	0.00	2365.00	0.00
2011	80.00	3780.00	0.00	5170.00	60.00	3115.00	1105.00	0.00	0.00	0.00
2012	0.00	55.00	0.00	2250.00	0.00	3595.00	0.00	0.00	0.00	0.00
2013	50.00	1920.00	0.00	0.00	21560.00	1777.00	0.00	0.00	0.00	0.00
2014	0.00	39.00	0.00	0.00	127853.00	8551.00	0.00	0.00	180.00	0.00
2015	0.00	2085.00	0.00	0.00	4800.00	950.00	2550.00	0.00	0.00	0.00
2016	15.00	350.00	0.00	0.00	0.00	5788.00	0.00	0.00	42.00	960.00
2017	11632.00	1395.00	0.00	0.00	0.00	2781.00	0.00	0.00	0.00	330.00
2018	0.00	25.00	0.00	0.00	0.00	1552.00	0.00	0.00	0.00	0.00

ii. Pt Colborne

Table B-23 Affected customer for Pt Colborne, PCH

	Number of affected customers									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	27345.00	2872.00	2016.00	7198.00	12901.00	3413.00	22.00	0.00	8.00	2241.00
2009	46109.00	36.00	4.00	526.00	43609.00	10618.00	6584.00	5.00	0.00	4747.00
2010	37341.00	2978.00	12.00	239.00	7694.00	7398.00	734.00	173.00	0.00	1961.00
2011	37949.00	295.00	0.00	1906.00	30303.00	18931.00	6069.00	1818.00	0.00	1823.00
2012	29231.00	159.00	6078.00	704.00	7107.00	11354.00	4504.00	1068.00	6166.00	9524.00
2013	10375.00	216.00	14.00	8644.00	8644.00	11786.00	4275.00	1757.00	13.00	3609.00
2014	53548.00	137.00	11.00	5258.00	9948.00	33532.00	3851.00	6.00	1488.00	4979.00
2015	51842.00	790.00	3200.00	4471.00	28344.00	4160.00	51059.00	0.00	6418.00	6063.00
2016	64189.00	1876.00	55.00	11106.00	7900.00	66635.00	11382.00	0.00	4.00	8788.00
2017	62036.00	730.00	27567.00	19434.00	9871.00	14746.00	72843.00	0.00	11173.00	4193.00
2018	32519.00	5.00	30049.00	14078.00	2.00	20715.00	18239.00	0.00	3560.00	2391.00

Table B-24 Interruption duration for Pt Colborne, PCH

	Interruption duration (Minutes)									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	8828.22	16494.00	74592	274656.4	7588.20	21248.40	1240.00	0.00	1620.00	8371
2009	106550.	1370.00	1040	21744.25	60529	153267.88	3130.02	210.00	0.00	738.80
2010	3578.70	76868.00	347	34203.00	22925	425851.87	18.38	8946	0.00	4576
2011	27440.77	6346.15	0.00	70197.40	531226	957126.65	5214.90	228.70	0.00	514
2012	172451.2	15579.00	127334	28852.00	112539	90573.10	11404.20	29565	67150.9	6227
2013	4446	16388.00	262	72011.88	5882.93	316966.80	2107.90	203812	1787.00	13160
2014	371323	5097.75	1025	20290.27	2013.72	213715.25	34670.50	360.00	104.35	7276.98
2015	44701	32013	441015	44436.00	106275	107096.25	569279	0.00	68277	12527
2016	137494.78	248932.00	4664.92	245486.02	3554.72	1878593.75	569.10	0.00	2340.00	27747.25
2017	116674.03	108821.57	1562846.80	389035.48	4685.12	122741.00	665535.22	0.00	515.25	6590.58
2018	120687.52	755.00	6076753.92	429101.88	100.00	118931.27	130999.35	0.00	37094.60	194.40

iii. Catharine

Table B-25 Affected customer for Catharine, PCH

	Number of affected customers									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	0.00	42.00	0.00	140.00	0.00	27.00	1.00	0.00	20.00	0.00
2009	0.00	0.00	0.00	0.00	0.00	34.00	0.00	0.00	0.00	0.00
2010	0.00	23.00	0.00	0.00	0.00	11.00	0.00	0.00	1.00	0.00
2011	0.00	62.00	0.00	1.00	0.00	17.00	40.00	0.00	0.00	0.00
2012	0.00	2.00	0.00	0.00	0.00	0.00	0.00	5.00	1689.00	0.00
2013	0.00	1.00	0.00	404.00	0.00	23.00	0.00	0.00	0.00	10.00
2014	0.00	1.00	0.00	0.00	0.00	50.00	0.00	0.00	0.00	0.00
2015	0.00	33.00	0.00	271.00	0.00	7.00	16.00	0.00	6.00	26.00
2016	55.00	0.00	0.00	0.00	0.00	78.00	0.00	0.00	2.00	0.00
2017	1.00	3.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	24.00	0.00	18.00	0.00	1.00	0.00	0.00	0.00	0.00

Table B-26 Interruption duration for Catharine, PCH

	Interruption duration (Minutes)									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	0.00	8046.00	0.00	14700.00	0.00	554.00	55.00	0.00	2200.00	0.00
2009	0.00	0.00	0.00	0.00	0.00	2413.00	0.00	0.00	0.00	0.00
2010	0.00	368.00	0.00	0.00	0.00	797.00	0.00	0.00	80.00	0.00
2011	0.00	630.00	0.00	50.00	0.00	2650.00	7400.00	0.00	0.00	0.00
2012	0.00	200.00	0.00	0.00	0.00	0.00	0.00	60.00	82757.00	0.00
2013	0.00	60.00	0.00	119845.25	0.00	4155.00	0.00	0.00	0.00	600.00
2014	0.00	4.00	0.00	0.00	0.00	615.00	0.00	0.00	0.00	0.00
2015	0.00	2120.00	0.00	6282.00	0.00	940.00	240.00	0.00	347.00	468.00
2016	4400.00	0.00	0.00	0.00	0.00	4141.00	0.00	0.00	340.00	0.00
2017	30.00	1798.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	720.00	0.00	378.00	0.00	30.00	0.00	0.00	0.00	0.00

iv. Jefferson

Table B-27 Affected customer for Jefferson, CNP

	Number of affected customers									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	0.00	2.00	0.00	1261.00	0.00	39.00	0.00	0.00	0.00	0.00
2009	633.00	15.00	0.00	457.00	586.00	3.00	514.00	0.00	0.00	0.00
2010	1.00	6.00	0.00	0.00	457.00	47.00	0.00	0.00	0.00	0.00
2011	0.00	15.00	0.00	46.00	0.00	102.00	0.00	0.00	1.00	0.00
2012	0.00	0.00	0.00	63.00	0.00	55.00	0.00	0.00	0.00	0.00
2013	0.00	18.00	0.00	8019.00	209.00	588.00	0.00	0.00	31.00	0.00
2014	2309.00	17.00	0.00	1.00	0.00	5540.00	514.00	0.00	15.00	0.00
2015	254.00	105.00	1312.00	75.00	0.00	15.00	0.00	0.00	0.00	0.00
2016	0.00	76.00	0.00	116.00	20.00	522.00	0.00	5.00	0.00	1315.00
2017	1612.00	1.00	0.00	4522.00	0.00	18.00	0.00	0.00	1.00	0.00
2018	0.00	0.00	0.00	49.00	0.00	2.00	0.00	0.00	0.00	0.00

Table B-28 Interruption duration for Jefferson, CNP

	Interruption duration (Minutes)									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	0.00	60.00	0.00	288287.78	0.00	2379.00	0.00	0.00	0.00	0.00
2009	2730.65	600.00	0.00	44875.68	51890.30	39.00	16807.68	0.00	0.00	0.00
2010	20.00	120.00	0.00	0.00	25028.37	4067.00	0.00	0.00	0.00	0.00
2011	0.00	1376.00	0.00	6980.00	0.00	3976.00	0.00	0.00	80.00	0.00
2012	0.00	0.00	0.00	519.00	0.00	2482.00	0.00	0.00	0.00	0.00
2013	0.00	458.00	0.00	563329.33	11455.30	36737.63	0.00	0.00	6510.00	0.00
2014	76.97	1005.00	0.00	20.00	0.00	6433.63	34206.00	0.00	5400.00	0.00
2015	20049.07	31035.00	172987.20	10400.00	0.00	959.00	0.00	0.00	0.00	0.00
2016	0.00	8727869.00	0.00	20165.00	1340.00	23637.93	0.00	350.00	0.00	65.75
2017	13240.50	1365.00	0.00	199223.80	0.00	4516.00	0.00	0.00	139.00	0.00
2018	0.00	0.00	0.00	4410.00	0.00	199.00	0.00	0.00	0.00	0.00

v. Fielden

Table B-29 Affected customer for Fielden, PCH

	Number of affected customers									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	20.00	17.00	0.00	0.00	2450.00	32.00	15.00	690.00	0.00	0.00
2009	0.00	662.00	0.00	356.00	415.00	116.00	678.00	1.00	0.00	0.00
2010	1596.00	1.00	0.00	0.00	0.00	1190.00	0.00	2.00	0.00	0.00
2011	1.00	21.00	0.00	62.00	1603.00	349.00	798.00	1603.00	0.00	0.00
2012	1.00	38.00	0.00	1.00	0.00	2466.00	25.00	0.00	0.00	0.00
2013	0.00	536.00	0.00	2369.00	0.00	23.00	0.00	6.00	0.00	0.00
2014	0.00	11.00	0.00	1.00	0.00	1178.00	0.00	0.00	0.00	0.00
2015	226.00	135.00	0.00	545.00	0.00	56.00	24.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	1911.00	0.00	553.00	0.00	1.00	0.00	0.00
2017	3.00	0.00	0.00	618.00	0.00	1771.00	0.00	0.00	0.00	0.00
2018	1.00	10.00	0.00	0.00	0.00	1479.00	438.00	0.00	0.00	0.00

Table B-30 Interruption duration for Fielden, PCH

	Interruption duration (Minutes)									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	840.00	1365.00	0.00	0.00	84993.33	1279.00	1125.00	72472.00	0.00	0.00
2009	0.00	12304.62	0.00	27683.40	3877.67	6217.00	39.55	30.00	0.00	0.00
2010	93.10	16.00	0.00	0.00	0.00	10196.67	0.00	420.00	0.00	0.00
2011	55.00	1100.00	0.00	1560.00	275451.13	1989.63	26.60	762.60	0.00	0.00
2012	5.00	10295.00	0.00	70.00	0.00	115643.07	3760.00	0.00	0.00	0.00
2013	0.00	7253.33	0.00	50010.93	0.00	1845.00	0.00	390.00	0.00	0.00
2014	0.00	430.00	0.00	30.00	0.00	25099.67	0.00	0.00	0.00	0.00
2015	26.25	7570.00	0.00	66895.00	0.00	1605.00	1211.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	42413.58	0.00	38445.75	0.00	15.00	0.00	0.00
2017	80.00	0.00	0.00	20597.70	0.00	120835.65	0.00	0.00	0.00	0.00
2018	60.00	1200.00	0.00	0.00	0.00	88034.42	41117.25	0.00	0.00	0.00

vi. Barrick

Table B-31 Affected customer for Barrick, PCH

	Number of affected customers									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	557.00	14.00	0.00	74.00	0.00	182.00	1.00	0.00	0.00	0.00
2009	1.00	173.00	0.00	2.00	0.00	18.00	0.00	0.00	8.00	0.00
2010	0.00	43.00	0.00	627.00	0.00	1060.00	0.00	17.00	14.00	0.00
2011	3.00	5.00	0.00	0.00	0.00	38.00	0.00	0.00	0.00	0.00
2012	1.00	149.00	0.00	0.00	0.00	2.00	0.00	0.00	1.00	30.00
2013	0.00	7.00	0.00	20.00	0.00	653.00	0.00	0.00	0.00	25.00
2014	620.00	342.00	0.00	0.00	0.00	12.00	0.00	0.00	0.00	0.00
2015	1191.00	214.00	1441.00	0.00	1141.00	13.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table B-32 Interruption duration for Barrick, PCH

	Interruption duration (Minutes)									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	9.28	2520.00	0.00	2430.00	0.00	46182.17	54.00	0.00	0.00	0.00
2009	5.00	5588.00	0.00	45.00	0.00	625.00	0.00	0.00	600.00	0.00
2010	0.00	4410.00	0.00	154415.00	0.00	105047.00	0.00	480.00	1489.00	0.00
2011	80.00	310.00	0.00	0.00	0.00	1567.00	0.00	0.00	0.00	0.00
2012	20.00	10005.00	0.00	0.00	0.00	25.00	0.00	0.00	120.00	4350.00
2013	0.00	210.00	0.00	1960.00	0.00	498.53	0.00	0.00	0.00	1100.00
2014	90.60	31663.00	0.00	0.00	0.00	4380.00	0.00	0.00	0.00	0.00
2015	4557.05	33404.00	276191.67	0.00	57.05	2080.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

vii. Sherkston

Table B-33 Affected customer for Sherkston, PCH

	Number of affected customers									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	0.00	29.00	0.00	9.00	0.00	9.00	0.00	0.00	0.00	0.00
2009	14.00	229.00	0.00	48.00	86.00	85.00	15.00	28.00	0.00	0.00
2010	0.00	0.00	0.00	4.00	1.00	11.00	0.00	0.00	0.00	0.00
2011	164.00	231.00	0.00	93.00	0.00	120.00	82.00	148.00	1.00	0.00
2012	0.00	61.00	0.00	3.00	0.00	6.00	0.00	0.00	0.00	0.00
2013	22.00	40.00	0.00	190.00	20.00	11.00	0.00	0.00	0.00	0.00
2014	257.00	7.00	0.00	67.00	0.00	3.00	257.00	0.00	0.00	0.00
2015	31.00	6.00	0.00	168.00	0.00	102.00	0.00	0.00	0.00	0.00
2016	16.00	2.00	0.00	326.00	33.00	2.00	0.00	0.00	0.00	0.00
2017	328.00	1.00	0.00	933.00	0.00	0.00	0.00	1.00	0.00	0.00
2018	0.00	0.00	0.00	187.00	0.00	18.00	1580.00	0.00	0.00	0.00

Table B-34 Interruption duration for Sherkston, PCH

	Interruption duration (Minutes)									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	0.00	7926.00	0.00	330.00	0.00	450.00	0.00	0.00	0.00	0.00
2009	4886.00	3394.80	0.00	8878.25	10686.00	3570.00	2700.00	4620.00	0.00	0.00
2010	0.00	0.00	0.00	620.00	90.00	520.00	0.00	0.00	0.00	0.00
2011	9.57	19795.02	0.00	17177.27	0.00	8679.15	2.73	14066.13	15.00	0.00
2012	0.00	16582.00	0.00	210.00	0.00	115.00	0.00	0.00	0.00	0.00
2013	0.92	5120.00	0.00	10721.00	7300.00	560.00	0.00	0.00	0.00	0.00
2014	42.83	300.00	0.00	4698.70	0.00	60.00	21.42	0.00	0.00	0.00
2015	2945.00	195.00	0.00	13543.00	0.00	18615.00	0.00	0.00	0.00	0.00
2016	896.00	100.00	0.00	43774.60	2701.15	190.00	0.00	0.00	0.00	0.00
2017	2980.15	45.00	0.00	90394.35	0.00	0.00	0.00	15.00	0.00	0.00
2018	0.00	0.00	0.00	97616.00	0.00	2229.00	59088.98	0.00	0.00	0.00

viii. Welland Hydro

Table B-35 Affected customer for Welland Hydro, PCH

	Number of affected customers									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	0.00	1.00	0.00	499.00	0.00	1.00	0.00	0.00	0.00	0.00
2009	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2011	0.00	0.00	0.00	0.00	0.00	6.00	0.00	0.00	0.00	0.00
2012	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2013	0.00	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2014	0.00	8.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00	0.00	1.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table B-36 Interruption duration for Welland Hydro, PCH

	Interruption duration (Minutes)									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	0.00	8.00	0.00	12104.77	0.00	105.00	0.00	0.00	0.00	0.00
2009	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2011	0.00	0.00	0.00	0.00	0.00	216.00	0.00	0.00	0.00	0.00
2012	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2013	0.00	70.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2014	0.00	810.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00	0.00	200.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

ix. Niagara Falls Hydro

Table B-37 Affected customer for Niagara Falls Hydro, PCH

	Number of affected customers									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	8.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2009	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2012	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2013	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table B-38 Interruption duration for Niagara Falls Hydro, PCH

	Interruption duration (Minutes)									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	0.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2009	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2012	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2013	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

x. Hydro One

Table B-39 Affected customer for Hydro One, PCH

	Number of affected customers									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2009	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2012	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2013	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2014	0.00	0.00	18653.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2015	0.00	0.00	7849.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	9250.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	73875.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	9191.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table B-40 Interruption duration for Hydro One, PCH

	Interruption duration (Minutes)									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2009	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

2012	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2013	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2014	0.00	0.00	776.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2015	0.00	0.00	179218.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	462.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	1256262.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	73528.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table B-41 Outage information for CNP Feeders

Feeder Name	Sum of customers affected	Sum of interruption durations (Min)	Feeder Name	Sum of customers affected	Sum of interruption durations (Min)
17L5	20537	946132.7	1264	15030	548183.6
17L8	33700	1165406	1266	12124	473315.3
17L9	72618	1869490	1261	7897	664164.7
17L67	273265	5878912	1267	5911	276970.5
18L5	117010	2040186	1269	1226	63690.15
18L8	166880	2319532	1272	3243	41232.87
18L10	137447	3276439	1361	313	9570
18L11	23247	500360.5	1362	656	91050
5RT7	546	97536	1363	0	0
8RT1	11663	292542.2	1364	0	0
9RT1	4773	185290.5	1365	0	0
9RT2	7183	342600.4	1366	0	0
9RT3	221	40515	1561	14101	422083.5
67RT1	7693	120403.9	1562	685	30268.07
67RT3	68041	3091654	1563	21457	583371.3
STATION 13	765	12240	1911	57414	2325290
STATION 19	5231	182473.4	1912	1450	216685
5RT1	0	0	1913	0	0
5RT2	130	10246.4	1921	18326	470411
5RT3	37	1640	1922	47125	951410.2
5RT6	403	108676	1923	197568	3940653
STATION 12 B3	1414	142389.8	RC17L8-1	39286	1143532
STATION 12 B1	1316	24499.53	67RT2	6509	180775.1
STATION 12 B2	9409	110797	67RT4	3522	173356.8
10RT1	10933	480616.4	RC18L10-1	45219	1586297
10RT2	187	20741	SMO1	12978	90025
10RT3	3545	195176.6	Murray HONI	78332	346122.2
11RT1	10303	227529.6	Station 11	143844	201854.2
STATION 15	0	0	Station 17	11922	772951
1265	8482	378642.9	Station 18	8064	1008000
1268	10067	590756.3	RC17L67-1	2019	1383
1270	8560	295998.6	Station 12	0	0
1271	268	16002.37	10RT4	2034	199415.2
1262	26321	998550.7	10RT5	6979	233426.9
1263	220	26440.72	8RT2	1971	115539.3
RC1921-1	5360	86035.62	RC18L10-2	1306	65.3

Table B-42 Outage information for CNP Feeders

Feeder Name	Sum of customers affected	Sum of interruption durations (Min)	Feeder Name	Sum of customers affected	Sum of interruption durations (Min)
43M9	196076	4717737	M12RT14	168	43438.67
KF1	260	26404	Welland Hydro12F1	517	13513.77
KF2	301	21203	NIAGARA FALLS HYDRO NF1	8	0.266667
KF3	155	14152	RCM11-2	51269	1368426
KF4	1829	221302	RCM11-1	13634	1182239
M9RT3	157	19893	BLD - 13	0	0
M9RT16	74	7700	RCM12-1	62656	818704.9
43M10	321034	4863509	Wilhelm	0	0
CF1	614	55617	RCM12-2	45780	900033.9
CF2	559	30341	41M13	11251	163230.2
CF3	751	133060.3	SM02	8507	42535
CF4	1221	51455	SF1	5168	415911.7
JF1	1579	-8633641	SF2	132	11194.33
JF2	2789	380416.2	SF3	236	15208.95
JF3	2860	194734.9	Hydro One Port Colborne TS	118818	1510248
FF1	6162	271243.7	SF5	7	1027.917
FF2	6887	316111.3	Sherkston DS	0	0
FF3	2067	113202.7	SF5	7	1027
FF4	11988	448278.1	RCM9-1	45112	944155.9
M10RT6	58	4255	RCM10-1	24358	952678.5
43M11	285484	2227148	RCM12-3	2352	19362.02
BF1	7394	567590.4	WF2	577	49744.8
BF2	1307	128998	M12RT1	670	104002
M11RT10	16	930	M12RT4	2799	456800.5
M12RT17	156	11463	M12RT5	872	64805
43M12	194294	893812	M12RT7	250	13579
WF1	5	631.25	M12RT11	78	7388
M12RT8	577	49744.8	M12RT12	162	21473.6