Distribution System Plan
2027-2031

alectra utilities

Exhibit 2A, Tab 1, Schedule 1

Alectra Utilities 2027-2031 Distribution System Plan

October 2025

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5.1 DSP Introduction

Alectra Utilities' Distribution System Plan (DSP) provides a detailed and comprehensive roadmap of the utility's Capital Investment Plan (CIP), and supporting information for the 2027-2031 planning period. The plan is responsive to customer needs, priorities, and preferences while addressing urgent and necessary work related to the distribution system infrastructure, equipment, and systems that safely and reliably service all 17 municipalities within Alectra Utilities service area. Alectra Utilities needs to invest $3.1B in capital over the 2027-2031 planning period, with a continued focus on renewing deteriorated infrastructure while meeting growing electricity demands and building a more resilient and modern grid in the face of increasing numbers of storms and adverse weather events. Figure 5.1 - 1 illustrates how the $3.1B investment relates to these three investment objectives.

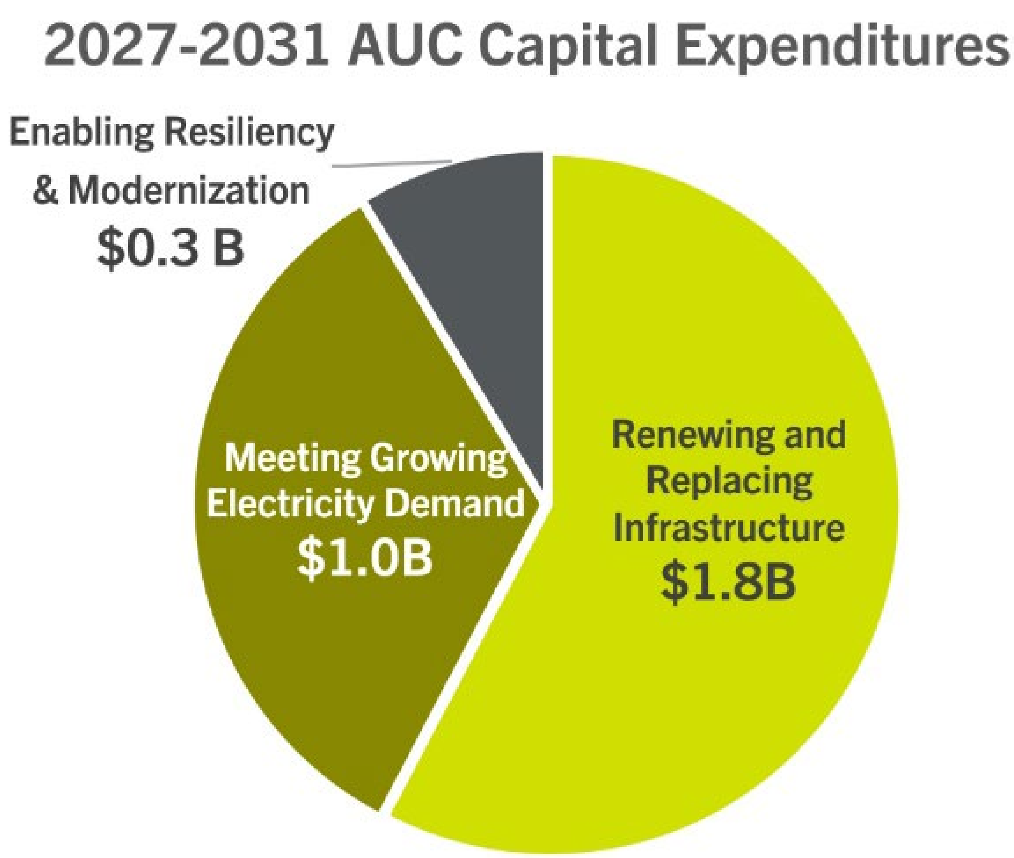

Figure 5.1 - 1 Capital Expenditures by Investment Themes

Renewing & Replacing Deteriorated Infrastructure

The focus of this investment objective is to address the significant backlog of deteriorated assets that pose a risk to Alectra Utilities' safety, reliability and operational efficiency. The required investment over the 2027 to 2031 period to achieve this objective is $1.8B and primarily includes:

- **Underground Asset Renewal** - Underground cable is Alectra Utilities' most deteriorated asset type, and a significant cause of outages on its system. Currently, nearly half of Alectra Utilities' controllable outages stem from deteriorated equipment directly jeopardizing both service reliability and safety.
- **Overhead Asset Renewal** - Alectra Utilities' Overhead Asset Renewal Program is a comprehensive, multi-year investment plan targeted at addressing the condition, functionality, and resilience of aging overhead distribution infrastructure.
- **Network Metering** - The Network Metering Program addresses regulatory compliance, asset health and technological obsolescence of the Alectra Utilities' over one million meters, as well as growth from new and upgraded connections.
- **Transformer Renewal** - The Transformer Renewal program addresses transformers that pose safety, environmental, and reliability risks through planned replacement.

Meeting Growing Electricity Demand

The focus of this investment objective is to ensure that Alectra Utilities meets its obligation to provide connections and adequate system capacity for customers' growing demand for electricity, aligned with municipal plans, regulatory mandates and provincial policies. The required investment over the 2027 to 2031 period to achieve this objective is $1.0B and primarily includes:

- **Station Capacity** - Alectra Utilities' Station Capacity investments include land acquisitions and construction of new stations, and capacity upgrades at existing substations. This also includes Capital Cost Recovery Agreement (CCRA) payments to Hydro One Networks Inc. (HONI) for a new transmission line connection and additional capacity upgrades at HONI-owned stations that supply Alectra Utilities' customers.

- **Customer Connections** - Customer Connections investments are required for connecting, modifying, or realigning Alectra Utilities' distribution system to provide customers with electricity access. These investments are mandatory, required by Alectra Utilities' license and the Distribution System Code (DSC).
- **Lines Capacity** - Lines Capacity investments are needed to prevent feeder overloading, safeguard power quality, and enable rapid restoration in the event of outages.
- **Road Authority & Transit Projects** - Road Authority projects require Alectra Utilities to perform work on the distribution system within the public right-of-way. Transit Projects are modifications to Alectra Utilities' distribution system that are initiated by transit or rail agencies at any jurisdictional level.

<u>Enabling Resiliency & Modernization</u>

The focus of this investment objective is to ensure that Alectra Utilities adapts and builds a resilient grid to mitigate the escalating risks from the increasing frequency and intensity of storms and extreme weather events. The required investment over the 2027 to 2031 period to achieve this objective is $0.3B, and includes coordinated investments in operational technologies, field automation, system control and telecommunications, customer-facing digital tools, and targeted rebuilds of high-risk rear-lot infrastructure.

The DSP outlines Alectra Utilities' necessary effort to renew a significant backlog of deteriorated infrastructure at risk of failure while balancing the evolving challenge of servicing growing communities in its service area. In addition, the DSP enables Alectra Utilities to incorporate climate resiliency and grid modernization, providing greater grid flexibility, reducing various risks (including system reliability, safety, environment, and efficiency) while building the capability to integrate emerging technologies, including Distributed Energy Resources (DER).

5.1.1 DSP Organization

Alectra Utilities has prepared this DSP in accordance with the Ontario Energy Board's December 9, 2024 *Filing Requirements for Electricity Distribution Rate Applications* (2025 Edition for 2026 Rate Applications), Chapter 5 (Distribution System Plan), and in alignment with the principles and objectives of the OEB's Renewed Regulatory Framework ("RRF").

The DSP is organized into three sections, which are generally named and numbered consistently with the DSP Filing Requirements, as follows.

- **Section 5.2 – Alectra Utilities Distribution System**: This section provides a summary overview of the DSP as well as describes the efforts Alectra Utilities has taken to Coordinate Planning with Third Parties. The section concludes with the setting of DSP-specific Performance Measurement for Continuous Improvement.
- **Section 5.3 – Asset Management Process**: This section provides an overview of Alectra Utilities' Asset Management Process used to develop the DSP. The section describes Alectra Utilities' service area, its distribution system and its customers. It provides a summary of the assets managed by Alectra Utilities as well as the description of the company's Asset Lifecycle Optimization policies and practices. The section includes a summary of System Capacity Assessment for Renewable Energy Generation and Distributed Energy Resources. The section concludes with a summary of Non-Wires Solutions to address system needs.
- **Section 5.4 – Capital Expenditure Plan**: This section describes Alectra Utilities' capital expenditure plans for its distribution system for the 2027 to 2031 period, and considers these plans relative to historical capital spending. The capital expenditure plans are the outcome of the asset management and investment planning process that has been informed by various drivers that are described in *Chapter 5.2 Distribution System Plan Overview*. The capital expenditure plan includes a series of 14 investment summaries, which describe groups of investments. The investment groups are organized based on the OEB's four investment categories. In addition, the capital expenditure plan includes narratives for Alectra Utilities investment groups, which summarize each capital investment group's drivers, benefits and risks, and analysis of options considered to support each capital investment.

5.2 Distribution System Plans

5.2.1 DSP Overview

5.2.1.1 Summary of Achievements - Previous DSP

The utility has completed its previous plan for 2020-2024, with adjustments for typical changes and evolving circumstances, including the impacts of the global COVID-19 pandemic, which altered customer-driven work demands, disrupted supply chains, and resulted in extraordinarily inflationary effects. Alectra Utilities had to manage its 2020-2024 capital plan with a constrained level of funding relative to the plan's needs and costs by reprioritizing projects and adjusting capital programs to deliver across a wide range of priority objectives and performance outcomes. Highlights of accomplishments include:

- Increased the pace of renewal of deteriorating and failing underground cable, which remains a top priority for Alectra Utilities. Failing cable and accessories resulted in 55% of all defective equipment hours of interruption over the 2020-2024 period.[1] Alectra Utilities completed 51 cable replacement and 57 cable injection projects over the 2020-2024 period, addressing the most pressing and urgent failing cables.
- Installed and operated grid automation switches to expedite restoration of service from outages and to increase system observability and drive operational productivity. In 2024, the use of automated switches avoided 15.51 minutes of System Average Interruption Duration Index ("SAIDI").[2]
- Implemented an advanced data analytics system to enhance capital planning capability to identify, design and implement investments which directly provide value for customers. Alectra Utilities' Asset Analytics Platform builds on its condition-based asset management process towards predictive analytics, reliability-driven maintenance and integrates multiple data sets to identify emerging reliability hotspots.

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[1] *Appendix B02 – Underground Asset Renewal*, Part I Overview, Pages 4, Figure B02 – 2 Customer Hours of Interruption Due to Defective Equipment, Alectra Utilities 5-Year Average (2020-2024)

[2] *Appendix B14 – Enabling Resiliency and Modernization*, Part II SCADA, Automation and System Control, Subsection 2.3 Investment Drivers and Needs, Page 20, Lines 20-23.

- Deployed a comprehensive Productivity Framework to initiate, approve, onboard, track and report on productivity initiatives as part of the continuous improvement process. The Productivity Framework guides the Utilities' efforts to deliver financial savings and efficiency benefits for customers.

5.2.1.2 Balancing Customer Preferences and System Needs

Despite the progress achieved during the 2020-2024 period, Alectra Utilities' requires investment in both short-term performance and long-term infrastructure so that the system can safely and reliably meet evolving and increasing energy needs. These efforts help to support the transition from the traditional one-way grid into a flexible, dynamic and resilient grid necessary to carry the economic growth, digitalization, proliferation of DERs which is adding complexity and urgency to modernizing the grid. Along with the necessary investments in infrastructure, Alectra Utilities' DSP also incorporates investment needs in the cybersecurity solutions and enterprise information technology systems required to dependably support real-time operations of the utility, and ensure responsiveness to customer needs and requests. Alectra Utilities' DSP demonstrates the minimum level of investment necessary to deliver outcomes for customers, meet diverse challenges and appropriately manage and steward the grid for safe and reliable operation.

Alectra Utilities balanced customer preferences and system needs in the DSP by considering:

- Reasonable price and reliability as top customer priorities, with reliable service for GS>50kW and large user customers becoming increasingly important.
- Customers' expectations to invest in enabling resiliency and grid modernization, with an increasing priority for restoration time in adverse weather conditions, as well as improving communications during outages.
- The majority of customers indicated to Alectra Utilities a preference to invest at the plan or above investment level for overhead and transformer renewal.

Alectra Utilities' DSP is designed to provide value for money and to balance appropriately: the needs and preferences of its customers; its distribution system requirements; and relevant public policy objectives. Based on the identified investment needs, Alectra Utilities developed and evaluated a solution through a consistent and uniform process, based on a Value Framework that assesses the value of an investment (from both a customer and organizational perspective) and risk mitigation. Leveraging a leading practice Asset Investment Planning Management (AIPM) optimization software, Copperleaf Portfolio (Copperleaf), Alectra Utilities developed an optimized portfolio of investments and presented fully-costed investment options and trade-offs to customers in the second phase of customer engagement. Alectra Utilities partnered with Innovative Research Group (Innovative) to conduct customer engagement to inform and shape this DSP. For both phases of engagement, Innovative gathered feedback from 61,135 Alectra Utilities customers, which represents the most significant customer engagement in the Ontario utility industry. When presented with investment options, an average of 86%[3] of Alectra Utilities' customers across all rate classes provided the social permission to proceed with the investment plan as presented.

5.2.1.3 System & Operating Context

This section provides an overview of the system and operational needs facing Alectra Utilities. For a comprehensive discussion of Alectra Utilities' existing distribution system assets, climate trends, and utilization, refer to *Chapter 5.3.2 Overview of Assets Managed*.

A Growing Backlog of Deteriorated Assets

Alectra Utilities conducts Asset Condition Assessments (ACA) of its distribution and station assets using a comprehensive Health Indexing (HI) methodology, which identifies deteriorated assets that require remedial action. Alectra Utilities' ACA was completed using industry best practices and was derived based on a comprehensive range of inputs, including inspection records, test results, asset attributes and historical utilization factors. The output of the ACA provides Alectra Utilities with a quantitative assessment of asset health and is used to identify deteriorated assets in poor and very poor condition. The continued operation of deteriorated assets significantly increases numerous risks to Alectra Utilities, its customers and the public, including system reliability, safety, environment, customer satisfaction and operational efficiency. Furthermore, deteriorated assets are more prone to failure during storms and adverse weather events as the remaining strength of the asset is diminished.

[3] Average of 86% social permission is based on Residential (81%), GS<50kW (77%), GS>50kW (86%) and Large Use (100%) customers.

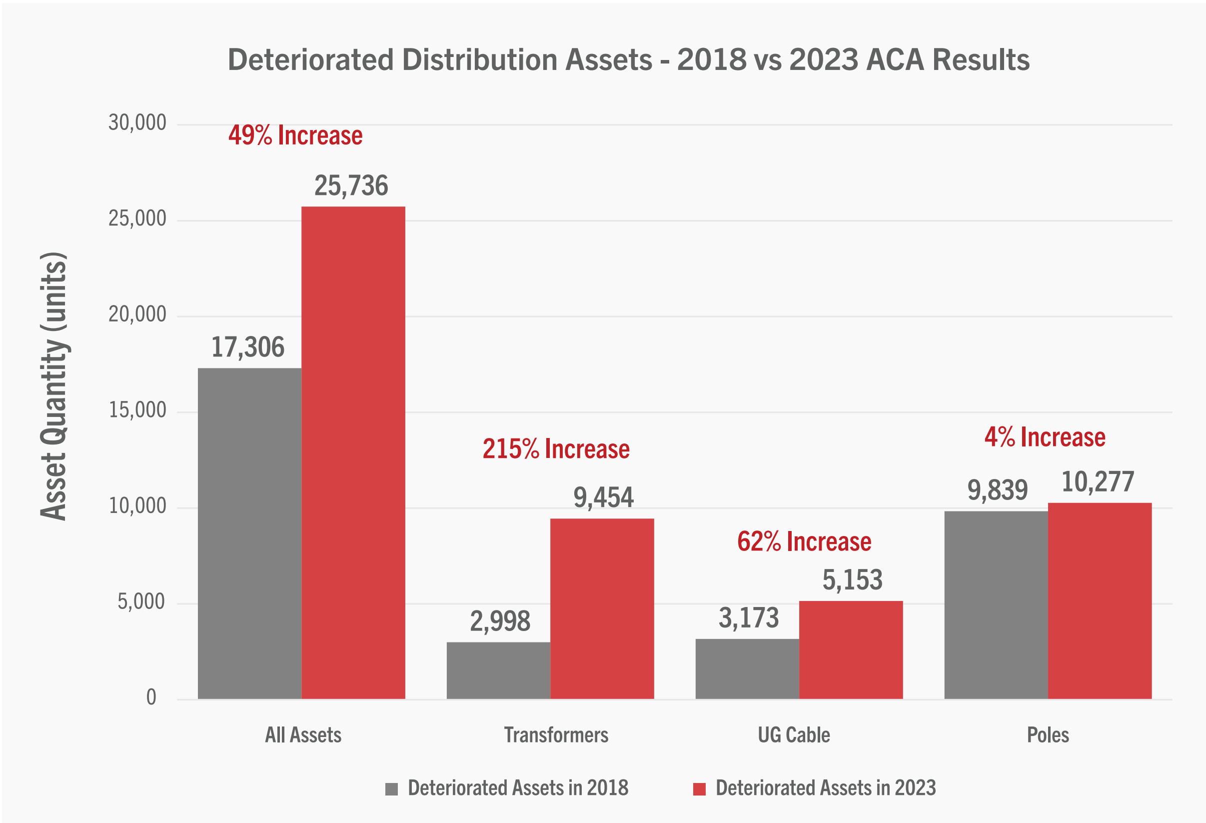

Figure 5.2.1 - 1 Alectra Utilities' Deteriorated Condition of Distribution Assets (2018, 2023)

Despite Alectra Utilities' effort to increase the pace of asset renewal, the backlog of deteriorated assets in Alectra Utilities' distribution system has increased by 49% from 2018 to 2023. Figure 5.2.1 - 1 illustrates that from 2018 to 2023, the backlog of deteriorated assets increased from 17,306 to 25,736 assets. The growth of the backlog results from Alectra Utilities' assets deteriorating at a faster pace than the pace of renewal. Urgent and necessary action is required to address this growing backlog and reduce the risks to operational efficiency, system reliability and safety, as presented in Figure 5.2.1 - 2, Figure 5.2.1 - 3 and Figure 5.2.1 - 4 respectively.

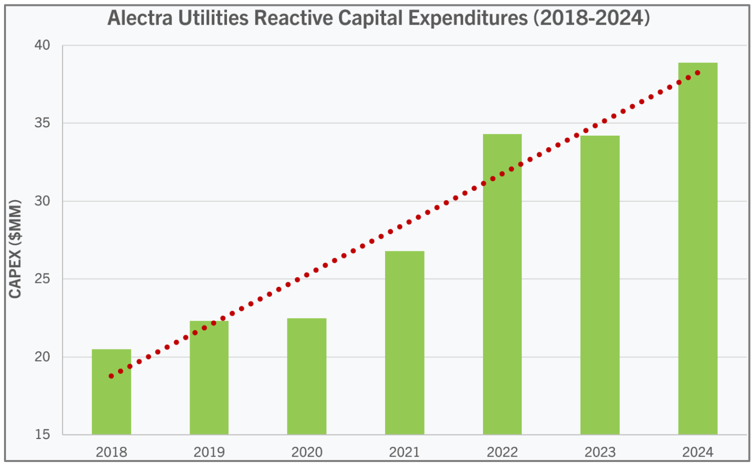

Figure 5.2.1 - 2 Alectra Utilities Reactive Capital Expenditures (2018-2024)

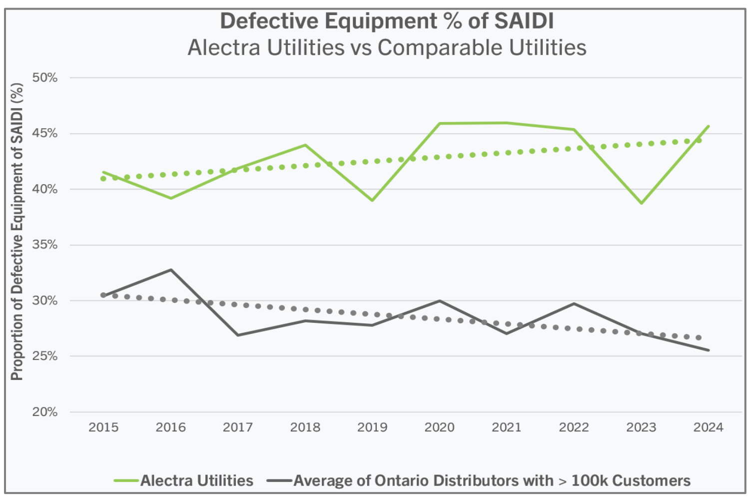

Figure 5.2.1 - 3 Defective Equipment as Percentage of SAIDI, Alectra Utilities vs. Comparable Utilities

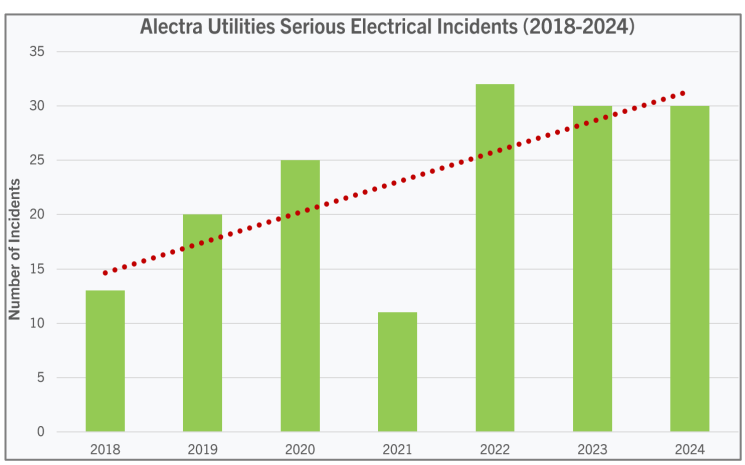

Figure 5.2.1 - 4 Alectra Utilities Serious Electrical Incidents (2018-2024)

B Operating a Large, Complex and Non-Contiguous Distribution System

Alectra Utilities was formed on February 1, 2017, through the consolidation of PowerStream Inc., Enersource Hydro Mississauga Inc., and Horizon Utilities Corporation, and the subsequent acquisition of Hydro One Brampton Inc. In addition, on January 1, 2019, Guelph Hydro Electric Systems Inc. was consolidated into Alectra Utilities. The result of Alectra Utilities' consolidation and acquisition is the formation of the second-largest electrical distributor in Ontario. The formation of Alectra Utilities has created a challenge for capital funding. Table 5.2.1 - 1 As listed in Table 5.2.1 - 1, the legacy utilities that formed Alectra Utilities have not rebased since 2017. Enersource Hydro Mississauga last rebased in 2013.

Table 5.2.1 - 1 Legacy Utility Rebasing Year & Application

Legacy Utility	Rebasing Year	Application
Enersource Hydro Mississauga	2013	COS (EB-2012-0033)
Hydro One Brampton	2015	COS (EB-2014-0083)
Horizon Utilities	2015	2015-2019 Custom IR (EB-2014-0002)
Guelph Hydro Electric System	2016	COS (EB-2015-0073)
PowerStream	2017	COS (EB-2015-0003)

The utility serves approximately 1.1 million customers in 17 municipalities, as illustrated in Figure 5.2.1 - 5. Alectra Utilities service area is non-contiguous with a large size of 1,912 square kilometers. Multiple geographies, degrees of urbanization and vintages of the distribution system characterize the challenges in the territory of the service area. These characteristics create a unique and challenging working environment for Alectra Utilities to maintain safe, reliable and efficient levels of service for its customers.

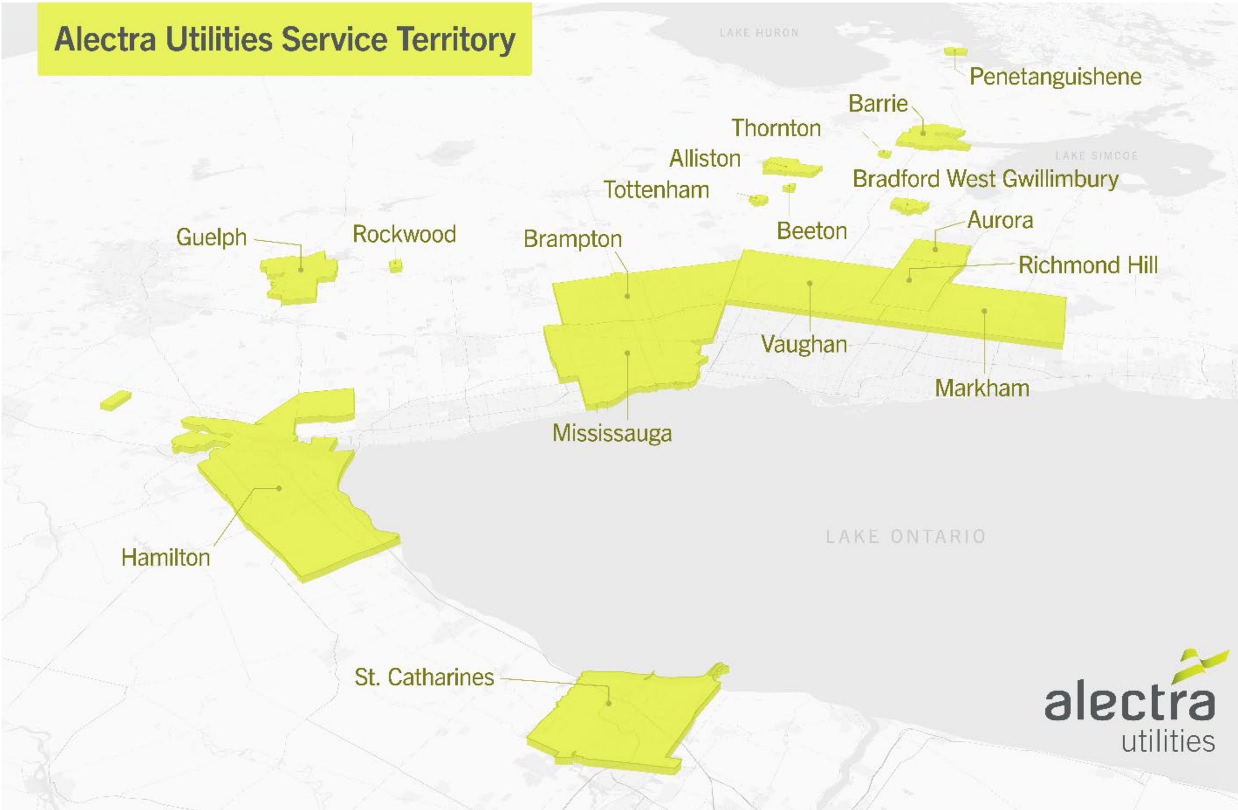

Figure 5.2.1 - 5 Alectra Utilities Service Territory

Alectra Utilities faces inherent challenges with operating in a large, discontinuous service territory, including logistical and electrical connectivity constraints. Alectra Utilities has divided the distribution system into six discrete system planning zones, as the distribution system is not electrically connected between each zone. This natural configuration limits and challenges Alectra Utilities in transferring available system capacity between each zone in its service area, especially during system outages or scheduled outages necessary for safe system maintenance activities. The dispersed distribution system in Southern Ontario also requires Alectra Utilities to participate in seven Integrated Regional Resource Plans (IRRP) with the Independent Electricity System Operator (IESO), Hydro One, various neighboring local distributors and other utilities.

The consolidation of legacy utilities has resulted in Alectra Utilities managing a wide range of legacy assets, system configurations and standards. Maintaining and operating a distribution system that includes a wide range of standards, legacies, and configurations efficiently is a unique challenge for Alectra Utilities that requires careful planning and logistics. The geography of the service area also includes a mix of urban (e.g., downtown Hamilton), suburban (e.g., Mississauga, Vaughan, Markham), and rural topographies (e.g., Thornton, Beaton, Penetanguishene), which requires Alectra Utilities to apply comprehensive standards and construction practices appropriate for each topography type. A dispersed and large service area also poses challenges to Alectra Utilities' operations, particularly in terms of adverse weather impacts and climate resilience. Storms and extreme weather events can pass through Alectra Utilities service area simultaneously or sequentially, challenging Alectra Utilities to implement emergency response systems, processes and practices that can respond quickly and deploy services to restore and repair the damaged system in various locations.

C Meeting Growing Electricity Demand

The population in Alectra Utilities' service area is projected to grow by 23.6% between 2024 and 2041, representing an annual growth rate of 1.4% which exceeds the projected provincial annual growth rate of 0.9% in the same period. Significant population growth is projected in Simcoe, York, Brampton and Guelph based on available greenfield development. Established municipalities of Hamilton and Mississauga are projected to experience population growth through intensification and redevelopment. This substantial population growth sets the need for new housing, transit solutions, and infrastructure, all of which need to be serviced by Alectra Utilities. Figure 5.2.1 - 6 illustrates the population and housing growth rates projected and presented by Alectra Utilities’ planning zones.

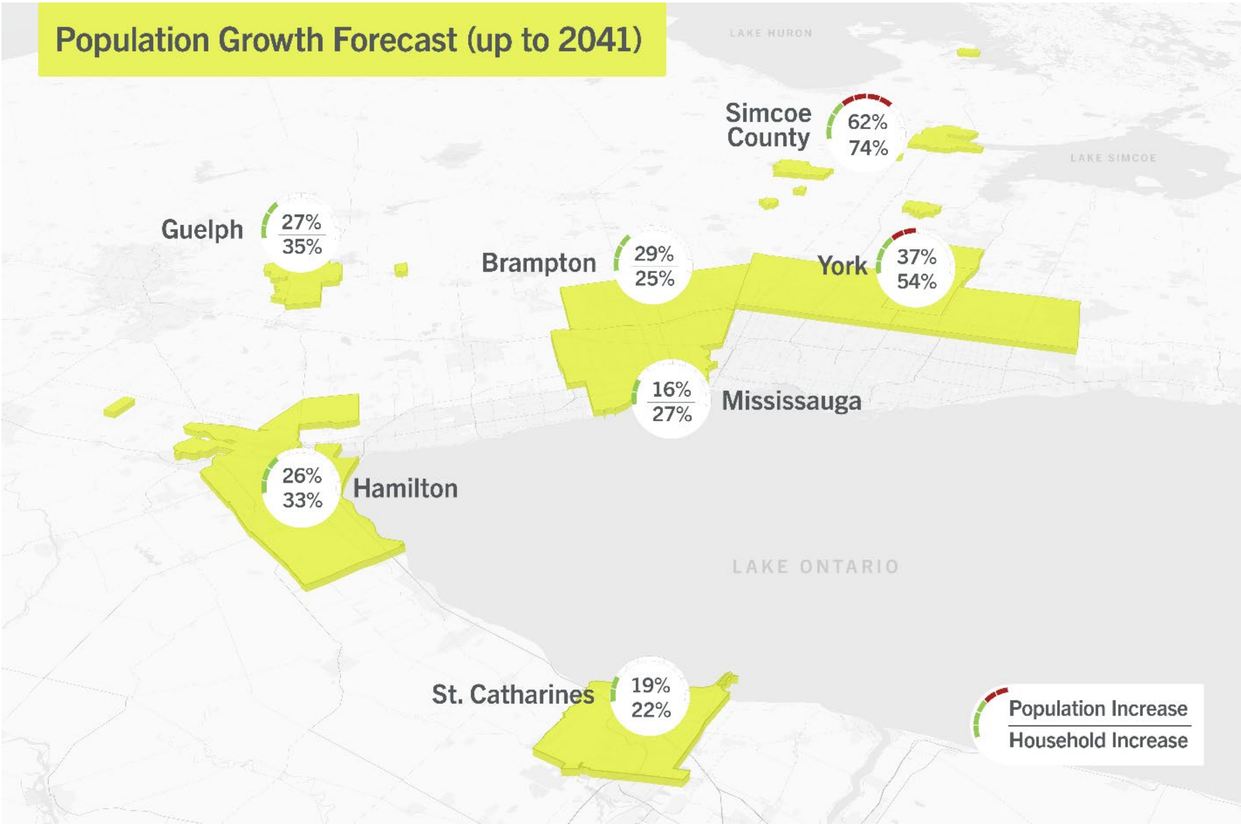

Figure 5.2.1 - 6 Population Growth Forecast (2021-2041) in Alectra Utilities Service Area[4]

In addition to working with each Municipality and Region to support economic growth and development, Alectra Utilities must also ensure that investment plans are aligned to meet the requirements of Provincial policies including "*Bill 162: The Get It Done Act, 2024*"[5], *"Bill 23: The More Homes Build Faster Act, 2022"*[6] as well as the *"Places to Grow: Growth Plan for the Greater Horseshoe*"[7]. Using Alectra Utilities load forecasting processes[8], the residential, commercial, industrial developments are projected to 'increase the system peak by 520MW from 2024 to 2031

Alectra Utilities is obligated to meet the new connection requirements resulting from the growing population and subsequent housing needs in all the municipalities of its service area and must ensure that there is sufficient system capacity to service all the customers and infrastructure

[4] *Chapter 5.3.2*, Table 5.3.2 - 2 Population & Household Growth Forecast – 2021-2041
[5] https://www.ola.org/en/legislative-business/bills/parliament-43/session-1/bill-162
[6] https://www.ola.org/en/legislative-business/bills/parliament-43/session-1/bill-23
[7] https://www.ontario.ca/document/place-grow-growth-plan-greater-golden-horseshoe
[8] *Appendix B13 – Station Capacity*, Table B13 - 2

requirements. The utility is also obligated to support this significant population and housing growth, which necessitates transportation infrastructure projects that encompass both road authority and transit development. There are numerous transportation projects under construction and in development in Alectra Utilities service area that the utility is obligated to support, including the Hazel McCallion Light Rail Transit, Dundas Bus Rapid Transit, GO Expansion, Yonge North Subway Extension, Hamilton Light Rail Transit, Queen Street & Highway 7 Bus Rapid Transit.[9, 10] In addition to the obligation to support all transit projects in its service area, Alectra Utilities must also ensure that there is sufficient system capacity to service such transportation system and facilities.

The substantial growth in population, housing and transportation in Alectra Utilities service area is also expected to lead to an increase in employment and other economic growth activities, increasing Industrial, Commercial & Institutional (ICI) service connections requirements. With the emergence of Artificial Intelligence (AI) technology and the growing demand for cloud computing services, Alectra Utilities must ensure sufficient system capacity is available to support the rapid growth driven by technology and digitization. Alectra Utilities' service area is one of Canada's largest and fastest-growing data center markets, with 115MW of connected data center load and 425MW of additional data center connections capacity committed by 2031. In addition to the rapid development of AI and cloud computing, Alectra Utilities is obligated to prepare the grid to meet the growing demand stemming from the uptake of electric vehicles, and corresponding charging infrastructure, as well as the transition to heat pumps. Alectra Utilities projects more than 500,000 electric vehicles in its service area by 2031 resulting in an additional 524MW[11]. Alectra Utilities customers transition towards new technologies and increase their dependence on electricity, the utility must provide for the evolving needs of customers driven by decarbonization efforts, increased electrification, the proliferation of DERs and the digitization of the economy.

D Safety & Security

Alectra Utilities prioritizes the safety and security of its employees, the public and the infrastructure, systems and data. The utility manages a wide range of legacy assets, infrastructure configurations and obsolete equipment that no longer meet present-day standards,

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[9] https://www.metrolinx.com/en/projects-and-programs/rapid-transit
[10] https://www.metrolinx.com/en/projects-and-programs/subways
[11] *Appendix B13 – Station Capacity*, Table B13 - 2

including rear-lot services, undersized conductors, direct-buried cables and obsolete station assets. The operation of such assets introduces hazards and high risks to safety for both Alectra employees and customers, as well as the public in general.[12] In addition to service interruption and outages that disrupt customers' lives and impact business operations, equipment failures also result in safety hazards, including live wire-down events, pole fires, oil leaks into the environment and poles falling to the ground, as well as crumbling underground vault structures.[13,14,15,16] Due to asset-specific deficiencies and infrastructure configuration issues, these assets create elevated reliability, safety and environmental risks. Alectra Utilities' Asset Management Process continuously monitors, detects, and responds to evolving distribution asset hazards and safety issues, protecting its employees, customers, and the public from harm, as well as mitigating damage to surrounding property and infrastructure.

In addition to safety risks and hazards in the distribution system assets, Alectra Utilities is committed to the security of its infrastructure and back-office systems. As Alectra Utilities, its customers and other third parties introduce emerging technologies and become increasingly connected, the utility must implement and maintain a robust security framework to maintain business continuity and protect customers and the communities Alectra Utilities serves. With the emergence of Artificial Intelligence and the increasing capabilities of rapidly evolving technologies, Alectra Utilities requires ongoing effort to address evolving cybersecurity threats to ensure the protection of critical infrastructure and systems. Alectra Utilities' distribution system provides critical energy infrastructure that supports residents and businesses of Ontario, including a major international airport, major hospitals, water treatment plants, and control rooms for both the provincial electrical transmission system and the provincial electricity system operator. Alectra Utilities is committed to mitigating the risk to the safety and security of its infrastructure and systems, and requires the necessary investments to ensure the implementation pace of safety and security measures is ahead of rapidly emerging threats.

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[12] Appendix B14 - Enabling Resiliency and Modernization, Part II Rear Lot, Section 3.3 Investment Drivers and Needs, Page 36-37, Lines 28-30 and Lines 1-5
[13] Appendix B03 - Transformer Renewal, Part 2 Investment Description, subsection Prolong Customer Interruption (Reliability Risk), Pages 4-7
[14] Appendix B01 - Overhead Renewal, Part II Pole Renewal, Section 2.1 Overview, Pages 10-11 Lines 6-13 and 3-7
[15] Appendix B01 - Overhead Renewal, Part III Overhead Rebuilds, Section 3.1, Pages 32-33, Lines 15-20
[16] Appendix B02 - Underground Renewal, Part IV, Section 4.3 Investment need, Page 47, Lines 6-14

E Enabling Resiliency & Modernization

The Ministry of Energy's "Vulnerability Assessment for Ontario's Electricity Distribution Sector" report[17] concluded that climate change is already having significant impacts on the province of Ontario and is guaranteed to affect the province in years and decades to come. Alectra Utilities' large, complex, and non-contiguous distribution system presents unique risks and challenges for the utility, as its service area is exposed to a wide range of climate-related hazards. Alectra Utilities engaged Hatch Ltd. (Hatch) to conduct a comprehensive Climate Risk and Vulnerability Assessment of the Utilities' distribution system. The assessment applied historical weather data, future climate models from the Intergovernmental Panel on Climate Change (IPCC), and outage data to identify vulnerabilities within Alectra Utilities' service area.

The outcome of the vulnerability assessment to climate perils identified localized risks to the distribution system assets and operations at Alectra Utilities. Climate projections identified that most adverse weather events will increase in frequency. As the intensity of adverse weather events escalates, the potential for more severe damage and longer recovery from storms grows. In certain instances, the frequency of adverse weather events is projected to be maintained (i.e. stable) at the current frequency of occurrence and the current risk levels. In addition to addressing the current climate perils of such climate parameters, Alectra Utilities must take urgent steps to increase the efforts to make the grid more resilient to those and new emerging climate perils projected to increase in the future. Table 5.2.1 - 2 provides a list of the climate parameters and frequency trends impacting Alectra Utilities service area.

Table 5.2.1 - 2 Climate Parameters and Frequency Trends

Climate Parameter	Trend in Frequency
Temperature above 32°C	**Increasing**
Temperature above 40°C	**Increasing**
Precipitation above 20mm	Stable
Precipitation above 50mm	**Increasing**
Wind Gust Below 60KM/h	Stable
Wind Gust Between 61 and 80KM/h	**Increasing**

[17] Ontario. *Vulnerable Assessment for Ontario's Electricity Distribution Sector*. Ministry of Energy, Government of Ontario, 2024. Page 1.

Climate Parameter	Trend in Frequency
Wind Gust Between 81 and 100KM/h	Stable
Wind Gust Between 101 and 120KM/h	Stable
Wind Gust Over 121KM/h	**Increasing**
Tornadoes	**Increasing**
Derechos	**Increasing**
Ice Storms	Stable

In addition to the identification of climate risk trends, the climate vulnerability assessment also provided Alectra Utilities with insights into localized climate perils. Cities of Barrie and Aurora are at risk of tornadoes, while Cities of Brampton and Mississauga are at high risk of extreme winds exceeding 100KM/h, and the City of Hamilton is at high risk of flooding. Due to the increasing frequency and intensity of storms, Alectra Utilities' planning and asset management processes must assess the risk and climate vulnerability of its system and take urgent action to improve grid resiliency through a range of solutions that include storm hardening and flexible, inclusive and integrated approaches utilizing emerging technologies.

Table 5.2.1 - 3 Climate Parameters and Risk Levels

Climate Parameter	Affected Area	Risk Level Present Climate Conditions	Risk Level Future Climate Conditions
Temperature Above 32°C	Mississauga, Brampton	High	High
Temperature Above 40°C	Vaughan, Mississauga, Brampton, Guelph-Rockwood	Very Low	High
Precipitation Above 20mm	Barrie, Vaughan, Mississauga, Brampton, Hamilton	High	High
Precipitation Above 50mm	Barrie, Richmond Hill, Vaughan, Mississauga, Brampton, Hamilton	High	High - Very High
Wind Gust Below 60KM/h	Richmond Hill	High	High
Wind Gust Between 61 and 80KM/h	Markham, Richmond Hill, Vaughan, Mississauga, Guelph-Rockwood, Hamilton, St. Catharines	High	High
Wind Gust Between 81 and 100KM/h	Markham, Richmond Hill, Vaughan, Guelph Rockwood, St. Catharines	High	High
Wind Gust Between 101 and 120KM/h	Brampton, Mississauga	Very High	Very High
	St. Catharines	High	High
Wind Gust Over 121KM/h	Mississauga, Brampton	Moderate	High
Tornadoes	Barrie, Aurora	Low - Moderate	High
Derechos	Mississauga, Hamilton	Low	Very High
	Barrie, Alliston-Thornton, Bradford, Aurora, Guelph-Rockwood, St. Catharines	Very Low	High
	Markham, Richmond Hill, Vaughan, Brampton	Low	High
Ice Storms	Barrie, Aurora, Markham, Richmond Hill, Vaughan, Brampton, Mississauga, Guelph-Rockwood, Hamilton, St. Catharines	High	High

Alectra Utilities' climate vulnerability assessment identified a significant risk increase in the majority of the municipalities served, as shown in Table 5.2.1 - 3. Risk levels associated with derechos are projected to increase across multiple areas, with the most significant increased risk levels in Mississauga and Brampton. Derechos are widespread windstorms that include rapidly moving showers and thunderstorms that produce destruction similar to that of tornadoes, with damage directed in one direction. Alectra Utilities customers experienced the impact of a derecho in May 2022, which impacted 297,650 customers, resulted in 1,515,747 customer hours of interruption and caused significant damage to the distribution system.

Alectra Utilities has appropriately incorporated the output of the climate risk and vulnerability assessment into its Asset Management Process and developed comprehensive solutions that include infrastructure hardening (e.g. upgrading class of poles, undergrounding vulnerable overhead assets), deployment of grid modernization solutions (grid automation to expedite restoration, Advanced Distribution Management Systems to optimize grid operations), integration of DERs and other Non-Wire Solutions (NWS) as well as implementation of customer service technologies including enhanced outage maps and alerts to keep customers informed of outages and restoration efforts.

F Innovation & Technology

Innovation and technology are driving the need for Alectra Utilities to evolve and modernize the grid into a dynamic system capable of facilitating complex interactions and integration of renewable and other Distributed Energy Resources, including electric vehicles, solar panels and battery energy storage systems. Customers continue to demonstrate growing interest in actively participating in the electricity systems as both consumers and producers of power. Alectra Utilities has experienced a significant number of DER connections in recent years. At the end of 2023, Alectra Utilities had 6,340 DER connections with a total installed capacity of 343MW on its grid, The utility projects that by 2031, the number of DER connections would increase to 9,161 with a total installed capacity of approximately 480MW, reflecting an increase of 40% in total generation capacity compared to 2023. Facilitating the connection and integration of DERs into the grid provides customers with more options and tools to actively manage their energy needs while providing Alectra Utilities with locally sourced energy resources. With a growing volume, magnitude and variety of DERs connected to the utility's grid, Alectra Utilities must implement enhanced grid monitoring and control solutions, including advanced network modelling. DERs have the potential to relieve grid constraints and improve grid resilience, but require accurate and real-time visibility as well as coordination capability to mitigate power quality issues, which include voltage excursion, thermal overload and unintended back-feed onto the grid. Alectra Utilities must address the significant challenge of an increasing volume of DERs capable of bi-directional power flows on a grid initially designed, protected and constructed for one-way power flows. Without the implementation of grid and back-office platforms to facilitate a modern and flexible grid, the risk of grid instability, adverse power quality and reliability impacts, as well as safety and security risks, increases with the growing number of DERs operating on Alectra Utilities' grid.

Evolving regulations and policies related to DER implementation and utilization are driving Alectra Utilities to prepare the grid, back-office systems and operations to facilitate safe, reliable and efficient integration of DERs. Interactions with Ontario's wholesale market are also evolving and introduce increased complexity as more DERs seek participation and inclusion. The IESO's Market Rules and operating procedures obligate distributors, including Alectra Utilities, to promptly comply with evolving requirements for the IESO-controlled grid and wholesale market. The IESO's Market Vision and Design Project and DER Roadmap have set a 2026 target for transmission and distribution coordination protocols that enable DER participation. These initiatives impose requirements on Alectra Utilities to provide accurate network models, load and DER forecasts with real-time power flow visibility, telemetry aggregation capability and software platforms to coordinate with both the IESO and DER participants, including DER aggregators.

In addition to facilitating a growing number of DERs connected onto its grid, Alectra Utilities also recognizes the potential value the Non-Wire Solutions (NWS) may provide as alternative solutions to traditional system investments. Although NWS are actively evolving and maturing, Alectra Utilities is committed to identifying, assessing and deploying NWS where such solutions can cost-effectively and reliably address emerging capacity challenges on the distribution system. The utility has identified five station projects (Newton TS, Nebo TS, Barrie MS, Melbourne MS, and Alliston MS) as candidates for NWS to address near-term forecasted capacity gaps driven by demand growth. Alectra Utilities' approach establishes a structured pathway for market-based resources to complement traditional wire solutions, aligning the DSP with evolving regulatory expectations and customer value objectives.

5.2.1.4 Development of the DSP

A Overview of the Asset Management Process

Alectra Utilities applied an established Asset Management Process to develop the Capital Investment Plan (CIP), which forms the basis of the 2027-2031 DSP. Alectra Utilities' DSP appropriately balanced: the needs and preferences of its customers; the utilities distribution system requirements; and relevant public policy objectives. The Asset Management Process is described in detail in *Chapter 5.3.1 Asset Management Process Overview*, and the process is depicted at a high level in Figure 5.2.1 - 7.

Figure 5.2.1 - 7 Overview of the Asset Management Process

The Asset Management Process starts with an assessment of a range of drivers that identify investment needs in Alectra Utilities' distribution system. These drivers are categorized as:

- **Customer Needs and Preferences** - Customer Engagement Phase 1: Alectra Utilities worked with its customers, to gather and understand their needs and preferences, to understand which investments will achieve aligned outcomes.
- **External Drivers:** Include external mandates and obligations that Alectra Utilities must satisfy, either as a condition of the Utilities' license or in response to public policy and regulations.

- **Internal Drivers**: The utility considers a range of distribution system and general plant needs to meet performance objectives, mitigate risks, ensure system capacity to safely and effectively operate the distribution system and continuous improvements initiatives.

After Alectra Utilities identified all the investment needs, the utility consolidated the needs into investment objectives for the 2027 to 2031 period as follows:

1. **Renewing and Replacing Infrastructure:** Focused investments to address asset renewal to reduce various risks (including operational efficiency, reliability, safety, and environment) associated with an increasing backlog of deteriorated and failing assets.
2. **Meeting Growing Electricity Demand:** Investments in customer connections and system capacity to meet the Utilities' obligations to service the growing population, housing, transit and employment developments in Alectra Utilities service area.
3. **Enabling Resilience and Modernization:** Investments to mitigate escalating risk levels from increasing frequency and intensity of storms and extreme weather events based on system vulnerability assessments. Investments in this theme include storm hardening and grid modernization initiatives to improve grid resiliency, flexibility and utilization of technologies (e.g. DERs).

Alectra Utilities developed a business case for each proposed capital investment consistent with and aligned with the Alectra Utilities Value Framework that includes cost, benefits and risk mitigation value measures. Business Cases developed using a consistent approach enabled Alectra Utilities to compare each business case across the entire portfolio of business cases. In the development of this DSP, Alectra Utilities produced business cases that represented over $5B of justified investment needs.

The utility leveraged Copperleaf software to optimize the capital investment plan. The Copperleaf software optimized the portfolio of approved business cases with the application of a multivariate maximization algorithm to develop a capital plan with maximum portfolio value, considering financial, resource and risk constraints. Next, Alectra Utilities drafted a plan based on the optimized capital plan and presented fully costed investment options and trade-offs to customers in the second phase of customer engagement.

Customers were presented with the draft optimized plan, complete with investment choices, in the second phase of customer engagement. 86%[18] of customers across all rate classes provided social permission for Alectra Utilities' proposed rate increases. Alectra Utilities incorporated customer feedback on the presented investment plans in the second phase of customer engagement by adjusting the draft plan:

- Accelerated investment in overhead asset renewal
- Reduced investment in system expansion
- Reduced investment in cable replacement
- Reduced investment in the deployment of AMI 2.0 meters

The overall adjustment to the draft plan resulted in a net reduction of $106MM of expenditures over the 2027-2031 period. With the inclusion of customer feedback, Alectra Utilities finalized the capital investment plan incorporated into the 2027-2031 DSP.

B Third-party Assurance Reviews

To objectively confirm that the methodologies and approaches taken by Alectra Utilities in preparing the DSP are reasonable and appropriate, the utility engaged Hatch, Kinectrics Inc. and AMCL as third-party experts to provide independent reviews of the system peak demand load forecast, asset condition assessment health index methodology, as well as the Value Framework and corresponding investment optimization methodologies, respectively. The result of this significant effort is a DSP that demonstrates how Alectra Utilities has aligned the outcomes of its Asset Management Process with the OEB's expected outcomes, as identified in the RRF, and the needs of the utility's distribution system and customers.

5.2.1.5 Overview of the 2027-2031 Capital Investment Plan

Over the 2027-2031 planning period, Alectra Utilities must invest to address system needs related to infrastructure renewal, growth and grid resilience. Alectra Utilities' capital investments for this planning period are necessary for effective and efficient delivery of distribution service to its customers and to ensure responsiveness to public policy and regulatory requirements. A detailed

[18] Average of 86% social permission is based on Residential (81%), GS<50kW (77%), GS>50kW (86%) and Large Use (100%) customers.

summary is provided in *Chapter 5.4.2 2027-2031 Investment Overview*. This chapter provides an overview of the capital investment plan, at a high-level.

Alectra Utilities grouped its investments into four categories identified in the Chapter 5 Filing Requirements, which are as follows:

- **System Access**: Investments that are modifications to the distribution system in which there exists an obligation to perform customer connections and comply with mandated service requirements.
- **System Renewal**: Investments that involved replacing or refurbishing system infrastructure which extend the service life of the assets.
- **System Service**: Investments that are modifications to the distribution system to ensure sufficient system capacity to meet future customer requirements and operational objectives are met.
- **General Plant**: Investments that are modifications, replacement or additions to assets where these are not part of the electrical distribution system (land, trucks, facilities, computers etc.)

A Needs and Drivers

Alectra Utilities' focus during the 2027 to 2031 period is on:

- **System Renewal** investments to address the large and growing population of deteriorated and failing infrastructure. Investment drivers include mitigation of risk to safety, reliability and environment, operational effectiveness, and grid resilience.
- **System Access** investments to facilitate effective and timely responses to customer connection and customer-driven system expansion requests, renewing failing metering infrastructure necessary to support accurate and timely settlement. Investment drivers include mandated service obligations, customer service requests, risk of meter failure and responsiveness to public policy.
- **System Service** investments required to ensure sufficient system capacity is available to meet the growing demands driven by organic growth and electrification. Investment drivers include system capacity, system reliability, operational effectiveness and grid resilience.

- **General Plant** investments to ensure operational systems, including IT, facilities, and fleet, remain secure, dependable, and efficient to support the operation of the organization. Investment drivers include operational effectiveness, functional obsolescence, failure risk, security and cybersecurity risks, and safety risk.

B 2027-2031 Capital Investment Plan Summary

Alectra Utilities has determined that significant investments are required to maintain the safe and reliable operation of its system and to meet customer needs. In particular, Alectra Utilities' distribution is impacted by a growing backlog of deteriorated assets that can only be addressed through sustained investment in renewing distribution equipment. These investments are related to the utility's underground distribution systems and overhead systems. Other important investment drivers include the need for system expansion to meet the increasing electricity demand from growth in population, housing, transportation and employment developments in its service area. Investments in grid resilience are required to mitigate escalating risk levels from increasing frequency and intensity of storms and extreme weather events based on system vulnerability assessments. Investments in this theme include storm hardening and grid modernization initiatives to improve grid resiliency, flexibility and utilization of technologies (e.g. DERs).

Table 5.2.1 - 4 Summary of Capital Investments – 2027-2031

	Forecast Period (Planned)				
	2027	2028	2029	2030	2031
System Access	157.7	180.4	164.2	139.1	138.7
System Renewal	193.1	209.4	257.3	346.1	362.6
System Service	39.2	79.6	150.0	132.0	184.2
General Plant	64.8	85.5	82.6	95.9	71.8
Total Capital Expenditure ($MM)	**454.8**	**554.9**	**654.1**	**713.1**	**757.3**

Over the 2027-2031 period, Alectra Utilities requires $1,368.5MM investment in system renewal for projects and programs to replace deteriorated distribution equipment to avoid failure risks, safety risks, and enable grid resilience. The utility needs $780.1MM of investment in system access to meet customer connection requests, system modification to accommodate customers, municipal and region-driven work (e.g. road authority), as well as replacement of metering infrastructure and other mandated service obligations. System service investment of $585.0MM is required to meet anticipated system capacity requirements, as well as investments in grid protection and automation to ensure operational and reliability service levels. General plant investments of $400.6MM over the 2027-2031 period include IT renewal and initiatives, fleet, facilities and capital contributions for transmission connections. A detailed breakdown by each investment category is provided in *Chapter 5.4.2 2027-2031 Investment Overview* and provided in summary below.

Summary of 2027-2031 System Access Investments

Table 5.2.1 - 5 System Access Investments (2027-2031)

	Forecast Period (Planned)				
System Access	**2027**	**2028**	**2029**	**2030**	**2031**
Network Metering	54.1	69.9	68.6	59.8	53.0
Customer Connections	75.1	91.3	82.4	66.0	72.0
Road Authority & Transit Projects	23.5	19.2	13.2	13.3	13.7
Transmitter Related Upgrades	5.0	0.0	0.0	0.0	0.0
Total Capital Expenditure ($MM)	**157.7**	**180.4**	**164.2**	**139.1**	**138.7**

Alectra Utilities requires $305.4MM of investment in Network Metering for the replacement of the first-generation smart meters at end-of-life and prone to failure. The second-generation smart meters (i.e. AMI 2.0) include enhanced functionality to provide real-time data and control over energy usage. The investment in metering will ensure that the meter-to-cash process is maintained. Provincial and municipal housing growth targets through the “More Homes Build Faster Act” will increase customer connection within Alectra Utilities service area and require $183.9MM of investment. Investment in customer connection will provide subdivision connections that are anticipated to increase starting in 2028 with growth across all operational areas. The utility needs $202.9MM of investment to meet its obligations to provide customer-initiated projects, which include customer-driven system expansions for commercial and industrial customers.

Summary of 2027-2031 System Renewal Investments

Table 5.2.1 - 6 System Renewal Investments (2027-2031)

	Forecast Period (Planned)				
System Renewal	**2027**	**2028**	**2029**	**2030**	**2031**
Overhead Asset Renewal	58.2	59.7	85.2	90.7	102.5
Reactive Capital	30.7	28.5	25.2	25.2	25.2
Rear Lot Conversion	0.0	0.0	20.3	32.7	33.6
Substation Renewal	7.5	9.6	13.1	14.7	18.7
Transformer Renewal	16.7	20.6	22.5	29.8	30.5
Underground Asset Renewal	80.0	91.0	91.0	153.0	152.1
Total Capital Expenditure ($MM)	**193.1**	**209.4**	**257.3**	**346.1**	**362.6**

Alectra Utilities' primary focus on system renewal continues to be addressing deteriorated underground cables and requires $567.1MM of investment over the 2027 to 2031 period. Investment levels for underground renewal need to increase in 2030 and 2031 as the utility concludes the cable injection program and transitions to full cable replacement. Alectra Utilities has determined that the candidates eligible for cable injection will exhaust in 2029. The utility requires $396.3MM in overhead renewal to address deteriorated poles that pose a safety hazard upon failure and bring risk of prolonged outages. Furthermore, deteriorated poles are vulnerable to storms and climate events. The utility also needs investment in voltage conversion to bring legacy infrastructure up to present-day standards to improve reliability and mitigate the need for costly station rebuilds. Alectra Utilities needs $120.1MM of investment to address deteriorated transformers which have doubled in population since 2018. Deteriorated transformers are prone to oil leaks, which may contain hazardous Polychlorinated Biphenyls (PCBs), posing environmental and public health risks and incurring costly remediation of soil.

Summary of 2027-2031 System Service Investments

Table 5.2.1 - 7 System Service Investments (2027-2031)

	Forecast Period (Planned)				
System Service	**2027**	**2028**	**2029**	**2030**	**2031**
SCADA & Automation	8.7	9.2	15.2	21.6	18.1
Capacity (Lines)	5.2	35.0	63.8	41.9	51.1
Capacity (Stations)	24.2	25.7	58.8	61.9	110.8
System Control, Communications & Performance	0.9	9.2	11.0	5.2	3.0
Safety & Security	0.0	0.2	0.9	1.1	1.1
DER Integration	0.2	0.3	0.3	0.3	0.1
Total Capital Expenditure ($MM)	**39.2**	**79.6**	**150.0**	**132.0**	**184.2**

Alectra Utilities requires $281.4MM of investment in Station Capacity investment to provide the capacity needed to meet anticipated demand growth based on municipal plans and provincial policies, including the "*More Homes Built Faster Act*". In addition to system expansion, Alectra Utilities requires $197.0MM of investment in line capacity to accommodate growth in multiple high-growth areas, including the Heritage Heights areas in North-West Brampton, Vaughan Metropolitan Centre, as well as Downtown Mississauga and Downtown Hamilton. The investment in line capacity will also provide relief to feeders that are currently operating over the planning limit[19]. The majority of system expansion investments in stations and lines provide capacity for known and anticipated growth in the Alectra Utilities service area. Over the 2027 to 2031 period, Alectra Utilities requires $72.8MM of investment in SCADA and grid automation to facilitate the deployment of automated switches in support of enabling grid flexibility and expedited service restoration from outages. Investment in grid modernization will also provide grid resilience to mitigate the increasing risk from climate perils.

[19] Planning limit of the feeder is two third rating of the maximum capacity of the feeder.

Summary of 2027-2031 General Plant Investments

Table 5.2.1 - 8 General Plant Investments (2027-2031)

	Forecast Period (Planned)				
General Plant	**2027**	**2028**	**2029**	**2030**	**2031**
Facilities Management	2.6	5.6	7.2	6.5	7.4
Information Technology	26.0	38.4	38.5	22.5	23.6
Fleet Renewal	24.2	23.3	18.6	17.3	14.5
Connection and Cost Recovery Agreements	10.0	16.3	16.3	47.5	24.1
Tools, Shop and Garage Equipment	2.0	1.9	2.0	2.1	2.2
Total Capital Expenditure ($MM)	**64.8**	**85.5**	**82.6**	**95.9**	**71.8**

Over the 2027 to 2031 period, Alectra Utilities needs investment of $149.0MM to implement several IT systems including:

- Enterprise wide systems for Billing & Collections (CIS), Customer Experience and Resource Planning (CX).
- Systems to support operational needs and efficient use of resource of the organization (Workforce Management, SCADA).
- Grid Operations and Asset Management for grid optimization and efficient analysis of grid control systems (Advanced Distribution Management System and Enterprise Asset Management).
- Financial system enhancements for Enterprise Resource Planning and Copperleaf
- Cyber-security enhancements to address growing threats of cyber risk and improvements to system resiliency and protection.
- Hardware and software investment to support efficient operations and administrative functions and to ensure employees have adequate tools to facilitate work tasks.

General plant investments also include $114.2MM for Connection & Cost Recovery Agreements (CCRA) with Hydro One to facilitate connection of the distribution system to the transmission grid. The utility needs $97.9MM of investment in fleet renewal to replace deteriorated vehicle and trucks to mitigate failure and reduce ongoing repair costs as well as investment to purchase additional vehicles to support the execution of the capital program and reduce Greenhouse Gases (GHG) emissions.

1 ### 5.2.1.6 Third-Party Studies and Assurance Reviews

2 Alectra Utilities' 2027-2031 DSP is supported by several expert studies and assurance reviews.

3 **Table 5.2.1 - 9 External Studies**

Study	Vendor	Description/Reference
Climate Risk & Vulnerability Assessment	Hatch Ltd.	To better understand the risks related to increases in extreme and severe weather due to climate change, Alectra Utilities engaged Hatch Ltd (Hatch) to conduct a comprehensive Climate Risk and Vulnerability Assessment of Alectra Utilities' distribution system. The assessment applied historical weather data, future climate models from the Intergovernmental Panel on Climate Change (IPCC), and outage data to identify vulnerabilities within Alectra Utilities' service area. The outcome of the vulnerability assessment to climate perils identified localized risks to the distribution system assets and operations at Alectra Utilities. The vulnerability assessment also provided Alectra Utilities with insights into localized climate perils. The Utility has appropriately incorporated the outputs of the climate risk and vulnerability assessment into its Asset Management Process and developed comprehensive solutions into the 2027-2031 DSP. The study is presented in *Appendix G*.
Copperleaf Value Framework Assurance Review	Asset Management Consulting Limited (AMCL)	Asset Management Consulting Limited (AMCL) was retained to conduct an independent assurance review of Alectra Utilities' Copperleaf Value Framework and business case optimization process. Furthermore, AMCL independently assessed Alectra Utilities' Value Framework against asset management best practice. AMCL concluded that Alectra Utilities has developed the Value Framework that demonstrates clear alignment with the four outcomes of OEB's RRF and its asset decision-making. AMCL concluded that this is appropriate and consistent with good public utility practice. AMCL found that the evaluation of investments and options against the Value Framework is well controlled and consistently applied. AMCL concluded that Alectra Utilities has implemented a structured, sequential approach to asset investment planning which is well practiced, effective and aligns to accepted industry good practice. The AMCL report is presented in *Appendix D*.

Study	Vendor	Description/Reference
Alectra 2024 Health Index Methodology Review	Kinectrics Inc.	Alectra Utilities retained Kinectrics Inc. (Kinectrics) to conduct an independent review of Alectra Utilities' Health Index (HI) methodology used for determining the condition of assets and how Alectra Utilities' methodology compares to best industry practices. To support the most cost-effective investment requirements, Alectra Utilities utilizes HI to determine the condition of its assets, ranging from "Very Good" to "Very Poor" condition. Kinectrics concluded that the input data and weights, test result interpretation, inspection record analysis and scoring criteria of the HI formula used by Alectra Utilities were well aligned with the best industry practices and represent a sound methodology for assessing the condition of assets. Furthermore, Kinectrics determined that, given the high quality of the HI methodology, the Asset Condition Assessment results should be highly credible. The Kinectrics assurance review is presented in *Appendix F*.
Load Forecast Study Review	Hatch Ltd.	Hatch was retained to conduct an independent review of Alectra Utilities' system peak demand forecast methodology, inputs and resulting 2024-2034 peak load forecast. In addition, Hatch reviewed the energy forecast model to ensure that the overarching assumptions for both forecasts were consistent. Hatch determined that Alectra Utilities used a best practice approach in preparing the system peak demand forecast. Hatch confirmed that Alectra Utilities used accepted approaches to the load forecast in alignment with OEB's Load Forecast Guidelines for Ontario. Hatch concluded that the Utility incorporated a wide range of reputable data sources and inputs in preparation of the forecast. Hatch observed that Alectra Utilities collected and used the most recently available plans for municipalities to develop the peak load forecast. Hatch also concluded that the methodology and assumptions used to develop the system peak demand load forecast are well-aligned with those used in the preparation of the energy forecast. The Hatch report is provided in *Appendix K*.

5.2.2 Coordinated Planning With Third Parties

5.2.2.1 Overview

Alectra Utilities coordinates its DSP with various third parties including customers, municipalities, neighbouring distributors, Hydro One Networks Inc. (HONI) Transmission and the IESO. The sections below summarize Alectra Utilities' consultations and coordinated planning activities with each party. Given the material influence of Regional Planning initiatives on the DSP, Alectra Utilities provides a detailed overview of the relevant Regional Planning processes and their impact on the capital investment plan.

5.2.2.2 Consultations with Customers

Alectra Utilities engages with customers formally and informally for multiple purposes. Alectra Utilities maintains regular interaction through its Customer Service group, Customer Connections group and Corporate Communications group via direct contact, online channels, social media, and forums.

The Corporate Communications group regularly releases newsletters and social media posts that outline upcoming investments in each of the municipalities.

When capital work is scheduled, Alectra Utilities engages with affected customers through town halls, presentations and focus groups.

Alectra Utilities employs several engagement methods to obtain input and feedback directly relevant to its short-term, medium-term and long-term planning of local and regional distribution-related infrastructure. This engagement is critical because Alectra Utilities' service territory includes rapidly growing communities and customers that operate essential infrastructure, such as data centers, major manufacturers and commercial service providers.

The key consultation methods are:

- Customer Engagement Process - Alectra Utilities carries out a formal engagement process with its customers to obtain preferences, present options and trade-offs, and obtain social permission for the DSP (refer to *Exhibit 1, Tab 5, Schedule 2 Application-Specific Customer Engagement*)
- Customer Satisfaction Surveys - Alectra Utilities collects feedback from all customer classes through customer satisfaction surveys (refer to *Chapter 5.2.3 Performance Measurement for Continuous Improvement*, to see how survey results inform DSP implementation).
- Key Account Meetings – Alectra Utilities provides specialized service to large commercial and industrial customers to accommodate their unique needs and requirements. Alectra Utilities' key account staff meet with customer representatives annually, or as needs arise, to review and discuss service requirements and concerns. These meetings provide feedback on reliability and power quality issues and offer insights into customer expansion plans, which Alectra Utilities incorporates into the long-term planning process and system renewal investment planning.
- Load Forecasting Meetings – Alectra Utilities holds annual meetings with planning and development staff from the municipalities it serves to discuss the anticipated peak demand forecast. In addition, Alectra Utilities meets with developers to discuss growth and forecasts for their planned development activities. Information from these meetings informs the planning process for new distribution system capacity and connection needs. This information is of particular interest for the purposes of planning and pacing of System Access and System Service projects (refer to *Appendix B10 - Customer Connections*, *Appendix B12 - Lines Capacity* and *Appendix B13 - Station Capacity*).

5.2.2.3 Coordination of Planning With Municipalities

Alectra Utilities consults with the municipalities and regions within its service territory through the consultations described below to inform its distribution system planning process.

A Load Forecasting Meetings

As previously noted, Alectra Utilities holds annual load forecasting meetings with municipal planning and development staff. These meetings identify emerging distribution system capacity and connection needs and inform System Access and System Service projects (refer to *Appendix B11 - Road Authority and Transit Projects* and *Appendix B13 - Stations Capacity*).

B Public Utility Coordination Meetings

Alectra Utilities participates in municipally initiated Public Utility Coordination meetings attended by municipal planning staff, gas utilities, telecommunications entities and other infrastructure owners. The purpose of these meetings is to coordinate activities of public utilities. Through these meetings, Alectra Utilities gains important insights into the planned work of the municipalities and other utilities, and identifies coordination opportunities for upcoming projects, such as road widenings, watermain expansions, and other utility construction plans, which it takes into consideration in its planning process.

C Municipal Energy Plans and Related Engagement

Alectra Utilities recognizes the critical role that its municipal partners play in shaping the future energy landscape, particularly as communities develop energy plans and pursue decarbonization goals. Alectra Utilities is proactively engaged in ongoing discussions with the municipalities it serves to support their Municipal Energy Plans and understand their long-term energy visions, growth projections, development strategies, and specific energy transition initiatives. This engagement aligns distribution system planning with municipal objectives and ensures the grid is prepared to support evolving community energy needs.

Beyond the formal Municipal Energy Plans process, Alectra Utilities engages in broader municipal energy-transition discussions. This collaboration may include participation in municipal standing working groups, technical consultations on specific development projects, and providing input on municipal bylaws and policies that have implications for electricity infrastructure and demand.

The scope of these discussions aligns with the planning horizons of both the municipalities and Alectra Utilities' DSP, focusing on the near-term (0-5 years), medium-term (5-10 years), and long-term (10+ years) impacts of municipal growth and energy transition initiatives on the distribution system.

C.1 Peel Region

Alectra Utilities provided detailed technical input into Peel Region's plan to decarbonize its buildings, outlining distribution system expansion and reinforcement requirements at approximately 50 sites where the region intends to convert to electric heating. This engagement allowed Alectra Utilities to gain early insight into potential load growth areas driven by municipal decarbonization efforts.

C.2 City of Hamilton

Alectra Utilities provided feedback and technical expertise to the City of Hamilton regarding its bylaw requiring residential parking spaces to be "EV ready". This engagement helps ensure that municipal requirements related to electric vehicle charging infrastructure are technically feasible from a distribution system perspective and informs Alectra's planning for localized load growth and potential infrastructure upgrades needed to support widespread EV adoption.

C.3 Ongoing Consultations

Beyond these specific examples, Alectra Utilities maintains regular contact with municipal planning and development departments across its service territory. These discussions cover topics such as new development timelines, zoning changes (impacting density and load), the potential for community energy projects, and the infrastructure implications of municipal climate action plans. This ongoing coordination ensures that Alectra Utilities' load forecasts and system expansion plans are informed by the current municipal growth and development information.

Through these coordinated efforts, Alectra Utilities aligns distribution system planning with municipal energy goals and development trajectories, contributing to efficient and effective infrastructure development and the successful realization of local energy transition objectives.

5.2.2.4 Coordination of Planning with Other Distributors

Alectra Utilities and Hydro One Networks Inc. (HONI) are embedded in each other’s distribution system. Alectra Utilities coordinates with HONI by providing load forecasting information and by discussing renewal and maintenance activities for shared facilities. For specific projects, both utilities convene outage coordination meetings between planning and operations staff to determine the sequence of activities and timing.

Due to the geographic size of Alectra Utilities, it shares territorial boundaries with several utilities. Alectra Utilities coordinates with all of these adjacent LDCs on relocation or expansion projects.

In addition, Alectra Utilities participates in all Regional Planning activities, as set out below in *Section 5.2.2.8*.

5.2.2.5 Coordination of Planning with Hydro One Transmission

Alectra Utilities' distribution system is supplied from 68 HONI-owned Transmission Stations and 14 Alectra Utilities-owned transmission stations connected to the HONI owned transmission grid. Alectra Utilities coordinates system planning with HONI Transmission pursuant to the Regional Planning Process. The process includes Integrated Regional Resource Planning (IRRP) led by the IESO, and Regional Infrastructure Planning (RIP) led by HONI Transmission. Project-specific meetings with HONI Transmission supplement these regional forums. Of the 21 regions established by the IESO for planning purposes, Alectra Utilities participates in seven regional planning processes and additional sub-regional planning activities in a few regions. *Section 5.2.2.8* describes these activities and their impact on the capital investment plan within this DSP in greater detail. *Appendix I - Hydro One Networks Inc Planning Status Letter* describes the status of planning activities coordinated with HONI Transmission.

5.2.2.6 Coordination of Planning With IESO

Alectra Utilities actively consults with the IESO as part of the Regional Planning Process, particularly in connection with the IESO-led Integrated Regional Resource Plan (IRRP). This includes participation in IRRP working groups, advice and recommendations regarding medium- and long-term electricity plans, and broader community engagement on regional electricity needs. Detailed discussion of the Regional Planning Process, Alectra Utilities' participation, and the resulting impacts on the company's capital investment plans in this DSP, are described in *Section 5.2.2.8*.

5.2.2.7 Coordination of Planning with Telecommunication Entities

Alectra Utilities coordinates capital-planning activities with telecommunication entities (Telecoms) in accordance with OEB requirements. Alectra Utilities applies the following practices:

A Annual Coordination Meetings

Alectra Utilities participates in annual coordination meetings, including the Public Utility Coordination Committee (PUCC) and Municipal Coordination (MC) sessions. Alectra Utilities can present its Capital Programs to municipalities and third-party stakeholders, including Telecoms, to identify opportunities for joint coordination.

The feedback from the annual coordination meetings enables Alectra Utilities to reprioritize or reschedule projects to accommodate joint-use opportunities.

B Project-Specific Coordination

Alectra Utilities coordinates with Telecoms on all capital projects.

At the start of the project design phase, the Design Technologist issues a Notice of Design Commencement to all relevant Telecoms recorded in the Joint Use (JU) system. When the design is finalized, the technologist issues a Notice of Design Completion that provides Telecoms with detailed construction information and timelines. Upon construction completion and the subsequent update of corporate records, Alectra Utilities provides to each Telecom provider a list of required transfers through the ATTACH JU system to facilitate the necessary transfers.

The joint-use coordination during the design phase frequently results in scope and schedule modifications (e.g., pole replacements or upgrades) to accommodate Telecom attachments and joint pole replacements and relocations, thereby minimizing disruption and preventing duplication of work.

For Transit, Customer Capital, and other customer-driven projects, the project owner assumes responsibility for coordinating with all relevant third parties, including Telecoms. For these projects, the owners such as: Metrolinx, municipalities, regions, or other road authority agencies will coordinate and circulate the drawings during the design process as part of Alectra Utilities' standard JU engagement.

C Post-construction Transfer Information

Upon completion of capital projects, Alectra Utilities updates its GIS system to reflect any pole status changes and issues monthly notifications to affected joint-use Telecoms through the JU Module until all required transfers have been completed. The post-construction follow-up ensures in its GIS and JU workflows continuous coordination until all Telecom obligations are satisfied.

5.2.2.8 Regional Planning Objectives and Process

Electricity system planning in Ontario is generally carried out at three levels:

- Bulk
- Regional
- Distribution

Bulk system planning considers the power system consisting largely of the 230kV and 500kV transmission networks. The bulk power system transfers large quantities of power between the provincial grid and neighbouring jurisdiction power systems, external to the province via interconnections. The bulk power system also connects major generation sources and delivers that power to major load centres in Ontario.

Regional planning considers supply and reliability issues at a regional level, with a focus largely on the 115kV and 230kV portions of the power system that supply various parts of Ontario. There are portions of the power system which can be electrically grouped together due to their bulk supply points and their electrical interrelationships whereby common facilities may impact many connected customers. From a transmission perspective, regional planning focuses on the facilities that provide electricity to the delivery points of the transmission connected customers, including distribution utilities. From a resource perspective, regional planning evaluates generation and demand reduction options, such as CDM, that may address identified supply and reliability issues in a region.

Distribution system planning is carried out by LDCs such as Alectra Utilities, the purpose of which is to evaluate investments to address the needs of the low voltage distribution system over the near and medium term, as reflected in this DSP.

Regional planning can overlap with bulk and distribution system planning. For example, bulk system planning overlap can occur at interface points or where regional resource options may address a bulk system issue. Distribution system planning can occur where the regional planning relates to transformer stations at which distributors receive power from the transmission system or where a distribution solution addresses the needs of the broader local area or region. Alectra Utilities therefore coordinates its planning efforts through the Regional Planning processes to promote efficiency and cost-effectiveness. Figure 5.2.2 - 1 illustrates the scope and relationships between three planning levels.

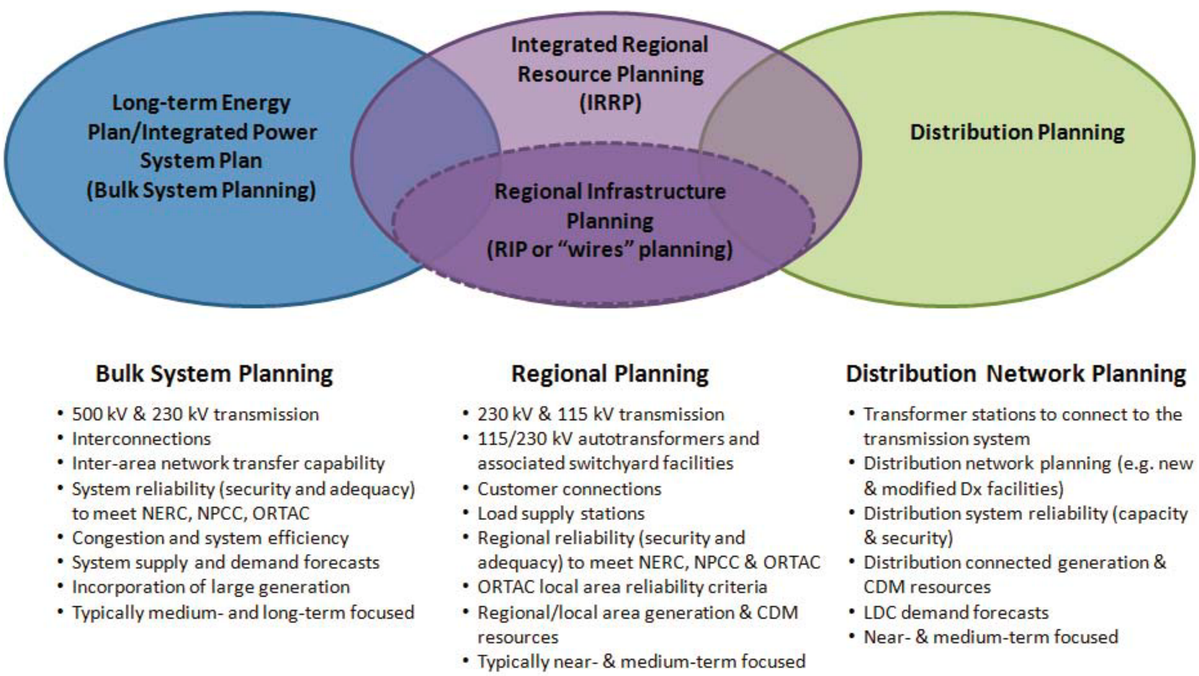

Figure 5.2.2 - 1 The Regional Planning Process

Regional Planning is a continuous process set out in the Planning Process Working Group (PPWG) Report to the Board[20] endorsed by the OEB in May 2013. It applies in 21 electricity regions across Ontario defined by electrical infrastructure boundaries. The process established in that report, which is illustrated in Figure 5.2.2 - 2, consists of four main steps:

- Needs Assessment (NA)
- Scoping Assessment (SA)

[20] https://oeb.ca/oeb/_Documents/EB-2011-0043/PPWG_Regional_Planning_Report_to_the_Board_No-App.pdf

- Integrated Regional Resource Plan (IRRP) Development
- Regional Infrastructure Plan (RIP) Development

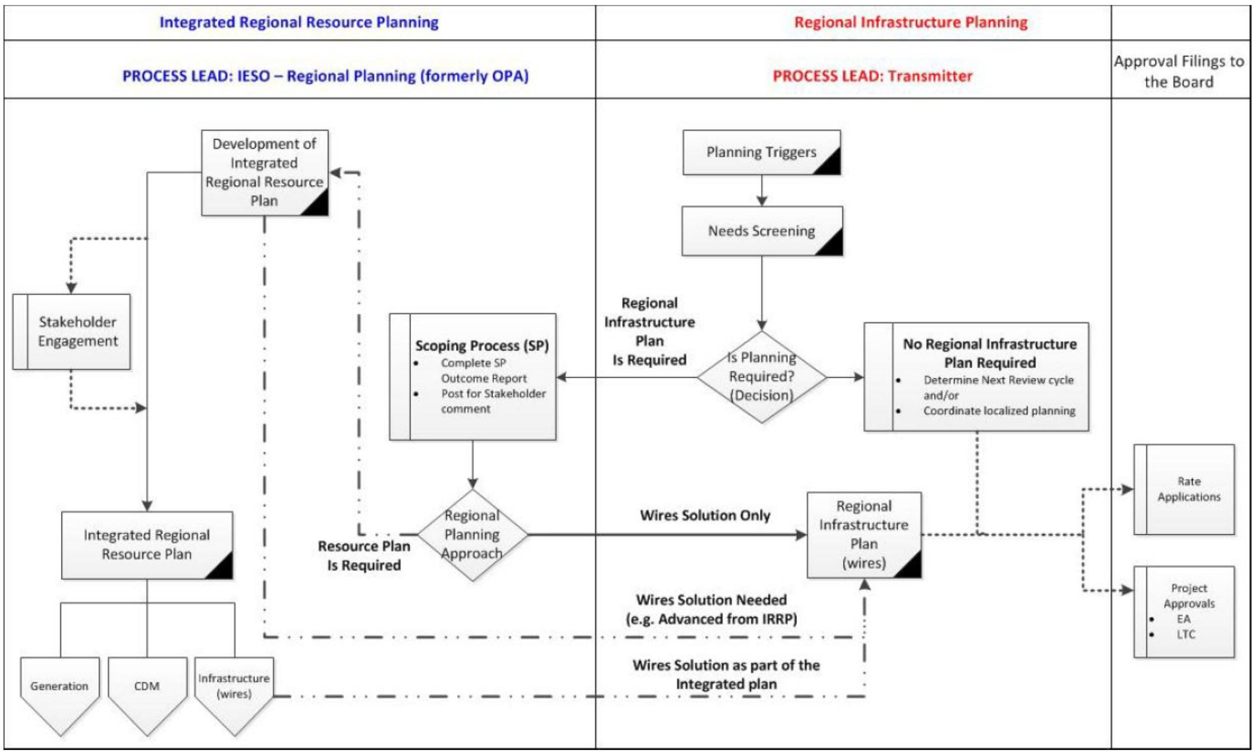

Figure 5.2.2 - 2 Regional Planning Process Flowchart[21]

The NA phase is led by the relevant transmitter to identify regional needs and is initiated every five years or earlier if a need is identified. The Technical Working Group (TWG), comprising of the IESO, HONI, and LDCs within the region under review, review the changes in demand in each area and performs an initial screen to identify needs in the region or sub-region using data from the IESO and the LDCs. If no action is required, or if the LDCs and the transmitter can resolve a need directly, for example a facility upgrade, the process concludes. Otherwise, if addressing the need requires coordination at the regional or sub-regional level, the process proceeds to the SA.

During the SA, TWG led by the IESO, in consultation with the transmitter and LDCs, reviews NA results, assesses non-wires alternatives, and determines the appropriate regional planning

[21] Planning Process Working Group Report to the Board 2013, Page 13

approach. If there is the potential to integrate a mix of different options, such as conservation, generation, distribution or new technologies, the working group recommends an IRRP. If needs can be met through focusing only on wires, meaning additions or improvements to transmission lines or infrastructure, the TWG recommends a RIP led by the transmitter. A third option includes the relevant LDC and the transmitter working together to plan necessary local infrastructure investments. The recommendations are published in a Scoping Assessment Outcome Report, which is made available for public comment as part of a community engagement process.

If an IRRP is required, an IESO-led working group, comprised of the transmitter and the relevant LDCs, develop a plan that integrates a variety of resource options to address the identified electricity needs of the region. These options can include:

- Conservation and Demand Management (CDM)
- Distributed generation
- Large-scale generation
- Transmission
- Distribution
- Innovative solutions, such as Distributed Energy Resources (DERs), which can include renewable generation, energy storage, combined heat and power, and microgrids

The group evaluates each option’s feasibility, cost, reliability, alignment with government policy directives, environmental performance, and community preferences.

Community and stakeholder engagement continues throughout the IRRP phase. When needed, a Local Advisory Committee (LAC) is established. LACs provide local input and recommendations, information on local priorities, and ideas on how best to engage the broader community in the conversation, all of which are considered throughout the planning processes.

If a RIP is required, because a wires-only solution has been identified as the best way to address planning needs, this process will be led by the relevant transmitter. The transmitter confirms the LDCs and other agencies that need to participate in the planning study. The RIP sets out the study scope, planning assumptions, confirmed needs, and the rationale for the recommended transmission solutions.

Final IRRPs and RIPs are posted on the IESO's and the relevant transmitter websites and may be filed as evidence in rate applications supporting specific infrastructure investments.

5.2.2.9 Alectra Utilities' Regional Planning Activities

Alectra Utilities has participated in Regional Planning Processes for the seven regions within its service territory, including applicable sub-regions. Alectra Utilities outlines each process and associated implications for its DSP in the subsequent sections below. Copies of the plans resulting from each of these processes are included in *Appendix H - Regional Planning Reports*.

Alectra Utilities plans investments for needs identified through regional planning for York Sub Region GTA West, Hamilton and Guelph.

The relevant regions and their sub-regions are as follows:

- A. Southern Georgian Bay/Muskoka Region
  - A.1 Barrie-Innisfil Sub-region
  - A.2 Parry Sound/Muskoka Sub-region
- B. GTA North
  - B.1 York Sub-region
- C. GTA West
- D. Toronto Region
- E. Burlington-Nanticoke
  - E.1 Hamilton Sub-region
- F. Niagara
- G. Kitchener, Waterloo, Cambridge and Guelph Region

A Southern Georgian Bay/Muskoka Region

The South Georgian Bay/Muskoka region is located in Central Ontario and includes all or part of County of Simcoe, County of Dufferin and District of Muskoka, District of Parry Sound and County of Grey.

The most recent regional planning cycle for Barrie/Innisfil and Parry Sound/Muskoka sub-regions was completed with the release of an Integrated Regional Resource Plan (IRRP) in May 2022.

In April 2020, HONI completed a Needs Assessment for the South Georgian Bay/Muskoka region. The corresponding report identified several needs that required regional coordination and recommended that the IESO lead the Scoping Assessment process which was completed in November 2020. The TWG comprised of staff from IESO, Hydro One and the local distribution companies HONI distribution, InnPower, Lakeland Power, Newmarket-Tay Power, Orangeville Hydro, Alectra Utilities, Elexicon Energy, Wasaga Distribution) participated in the Scoping Assessment process. The TWG further reviewed the needs and identified two sub-regions – Barrie/Innisfil and Parry Sound/Muskoka for further study through the regional planning process.

Alectra Utilities' Barrie and Penetanguishene service areas fall within the Barrie/Innisfil Sub-region and Parry Sound/Muskoka Sub-region.

In November 2020, the South Georgian Bay/Muskoka Scoping Assessment Outcome Report was issued, a copy of which can be found in *Appendix H01 - South Georgian Bay - Muskoka Scoping Assessment*. The RIP was issued in 2022 and identified upgrades to several stations which were to be undertaken by HONI (refer to *Appendix H02 - South Georgian Bay - Muskoka Regional Infrastructure Plan*).

A.1 Barrie-Innisfil Subregion

A map of the sub-region is illustrated in Figure 5.2.2 - 3. The process to develop the Barrie/Innisfil IRRP was initiated in 2020. A subsequent Scoping Assessment Report produced by the IESO recommended to conduct an Integrated Regional Resource Plan (IRRP) for the Barrie/Innisfil sub-region to evaluate integrated solutions and ensure coordination with regional and bulk system assessments.

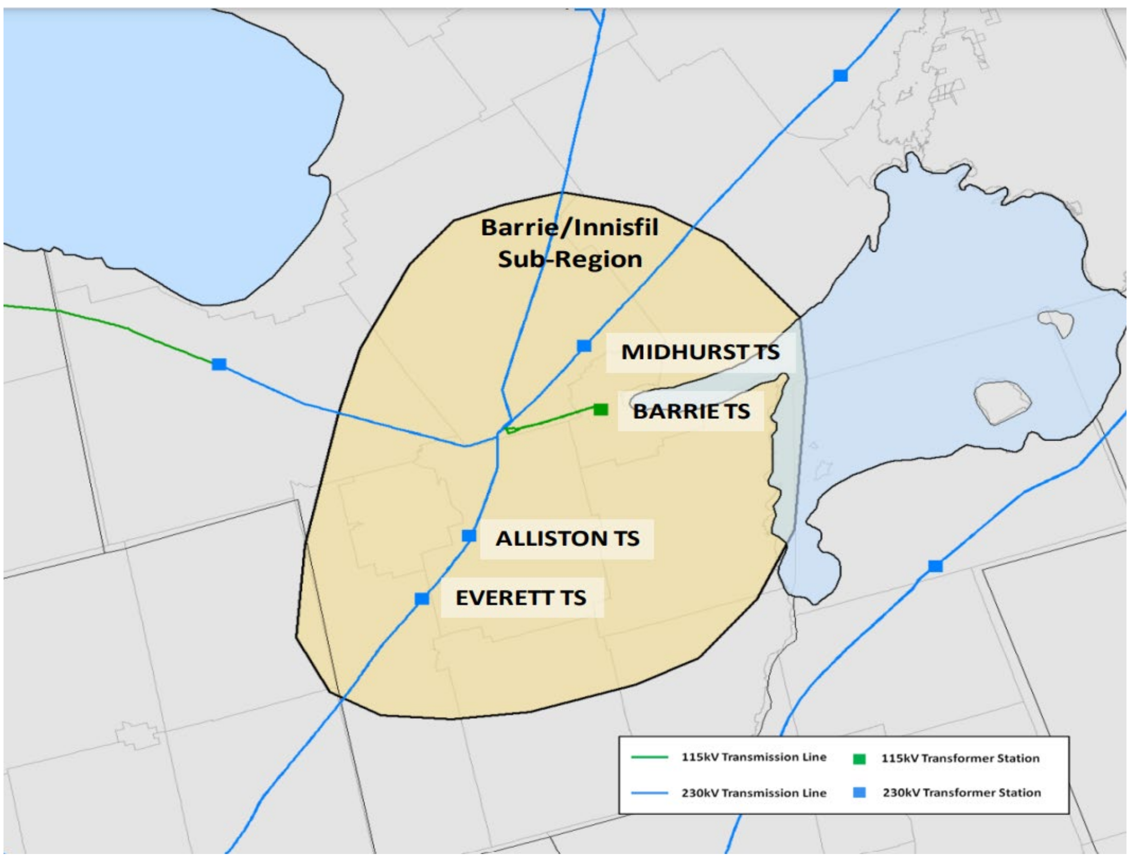

Figure 5.2.2 - 3 Map of Barrie/Innisfil Sub-region (Sourced from IRRP)[22]

The IRRP, issued in May 2022, identified the sub-region needs, summarized in Table 5.2.2 - 1 (refer to *Appendix H03 - Barrie Innisfil Sub–region IRRP).*

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[22] *Appendix H03 Barrie Innisfil Sub–Region IRRP* 2022 Page 9

Table 5.2.2 - 1 Barrie/Innisfil Sub-region Needs[23]

No	Need	Need Description	Need Date
1	Alliston Station Capacity	Alliston TS demand forecast will exceed summer 10-day LTR	2037
2	Barrie Station Capacity	Barrie TS demand forecast will exceed summer 10-day LTR	2027
3	Everett Station Capacity	Everett TS demand forecast will exceed summer 10-day LTR	2025
4	Midhurst Station Capacity	Midhurst TS demand forecast will exceed summer 10-day LTR	2035
5	M6E/M7E Supply Capacity	After a loss of either M6E or M7E, the remaining circuit exceed LTE	2034
6	End-of-Life refurbishments	Sections of M6E/M7E and E8V/E9	Various
7	Essa Bulk System Supply	Essa transformer overload of loss of remaining 500/230kV autotransformer	Today

[23] Barris Innisfil IRRP 2020, May 2022, Page 26

Figure 5.2.2 - 4 illustrates the range of electricity demand forecast scenarios provided in the 2022 IRRP. Even with the upgrade of Barrie TS in 2024, the NA projects that the transformation capacity will be exceeded in 2027.

HONI Transmission has begun gathering updated load forecasts for the next NA to commence the 2025 new regional planning cycle.

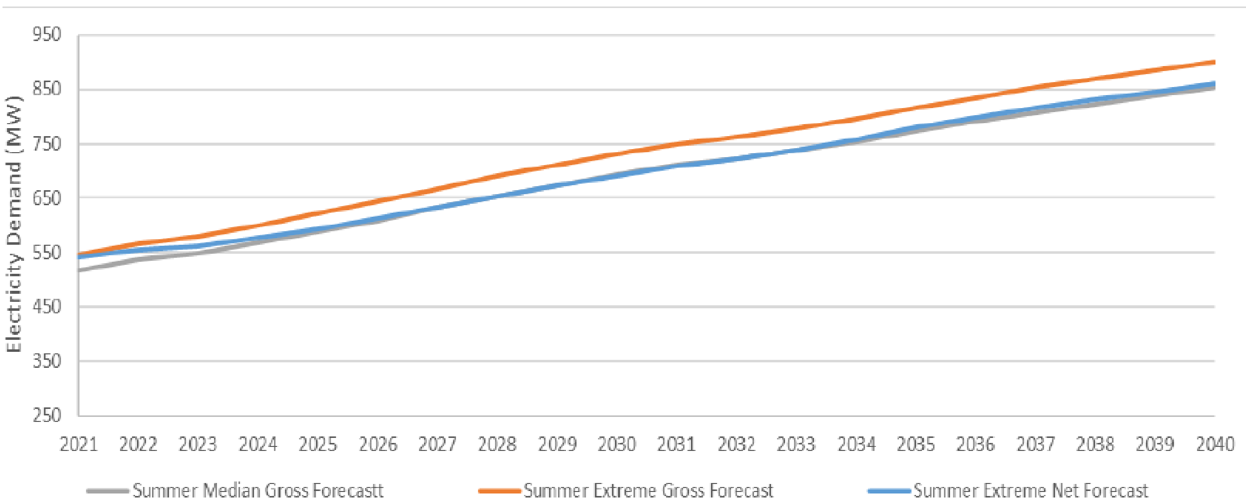

Figure 5.2.2 - 4 Barrie/Innisfil Demand Forecast Scenarios[24]

Alectra Utilities confirms it does not require any investments to meet regional planning needs, however it has identified distribution-level station capacity needs to be addressed within this DSP (refer to *Appendix B13 - Stations Capacity (Section 3.2.1.2)).*

A.2 Parry Sound/Muskoka sub-region

In May 2022, the second cycle of IRRP for the Parry Sound/Muskoka Sub-region was completed. Alectra Utilities' service territory (i.e. Penetanguishene) falls within the Parry Sound/Muskoka sub-region and is supplied by Waubaushene TS. Midhurst TS is also included in the Parry Sound/Muskoka IRRP since it is supplied by the Muskoka-Orillia 230kV sub-system (refer to Figure 5.2.2 - 5 for a map of the transmission systems in this region).

[24] *Appendix H03 Barrie Innisfil Sub–Region IRRP 2022*, Page 27

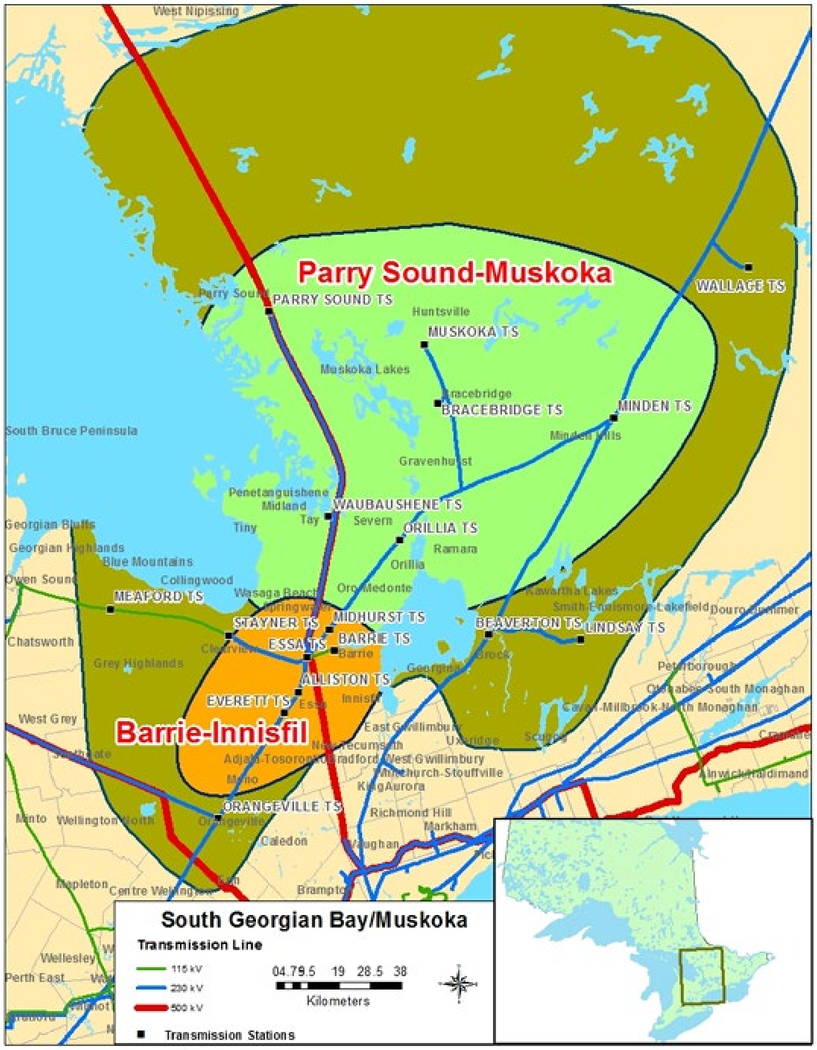

Figure 5.2.2 - 5 Parry Sound/Muskoka Transmission System[25]

[25] Parry Sound Muskoka Sub Region-NA 2020, Page 10

Over the 20-year period from 2021-2040, this subregion is forecast to experience an 18% increase in electricity demand as shown in Figure 5.2.2 - 6.

Over the longer term it was projected that the electricity demand growth could also exceed the supply capability of the Muskoka-Orillia 230kV sub-system. These needs will be revisited in the next iteration of the IRRP for this sub-region (refer to *Appendix H04 Parry Sound - Muskoka Sub-region IRRP*).

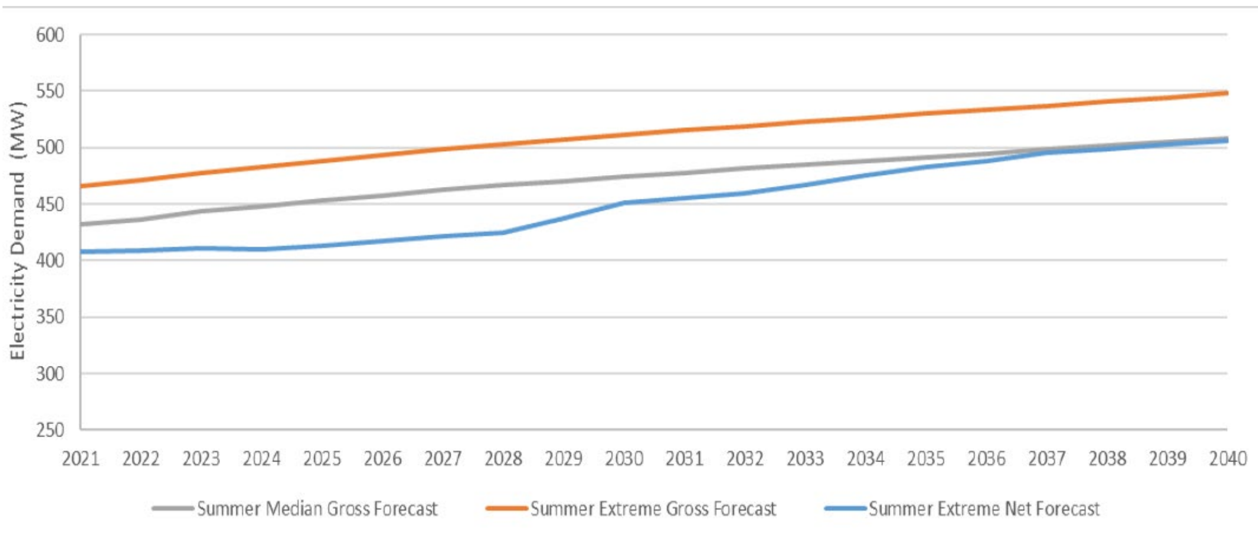

Figure 5.2.2 - 6 Parry Sound/Muskoka Sub-region Planning Forecast (2021-2040) [26]

Alectra Utilities confirms that the Parry Sounds/Muskoka IRRP does not require investments at the regional level in this DSP.

B GTA North

The GTA North Region approximately follows the boundaries of the Regional Municipality of York and includes parts of the Cities of Toronto, Brampton and Mississauga. Figure 5.2.2 - 8 illustrates the GTA North transmission system.

[26] *Appendix H04 Parry Sound - Muskoka Sub-Region IRRP* 2022, Page 23

The region is divided into two sub-regions:

- York Sub-region

  This area includes Southern York area (i.e. the Municipalities of Vaughan, Markham, and Richmond Hill) and Northern York area (i.e. the Municipalities of Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville, Georgina, and some parts of Durham and Simcoe regions are supplied from the same electricity infrastructure).

- Western Sub-region

  This area comprises the western portion of the City of Vaughan.

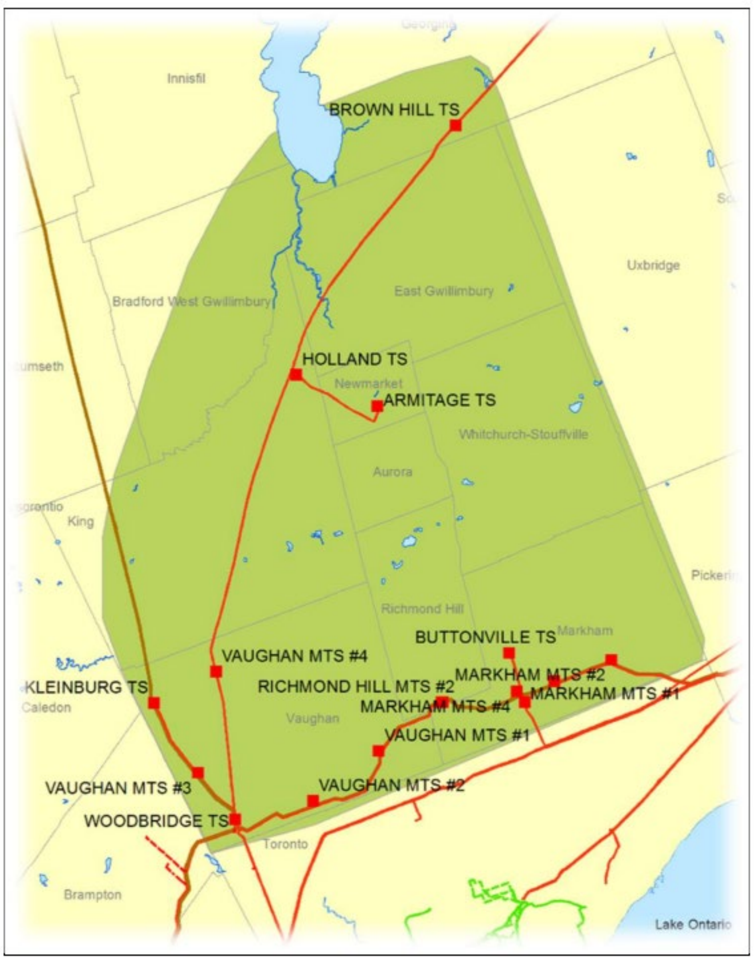

Figure 5.2.2 - 7 GTA North Supply Area[27]

[27] GTA North Region-NA 2023, Page 8

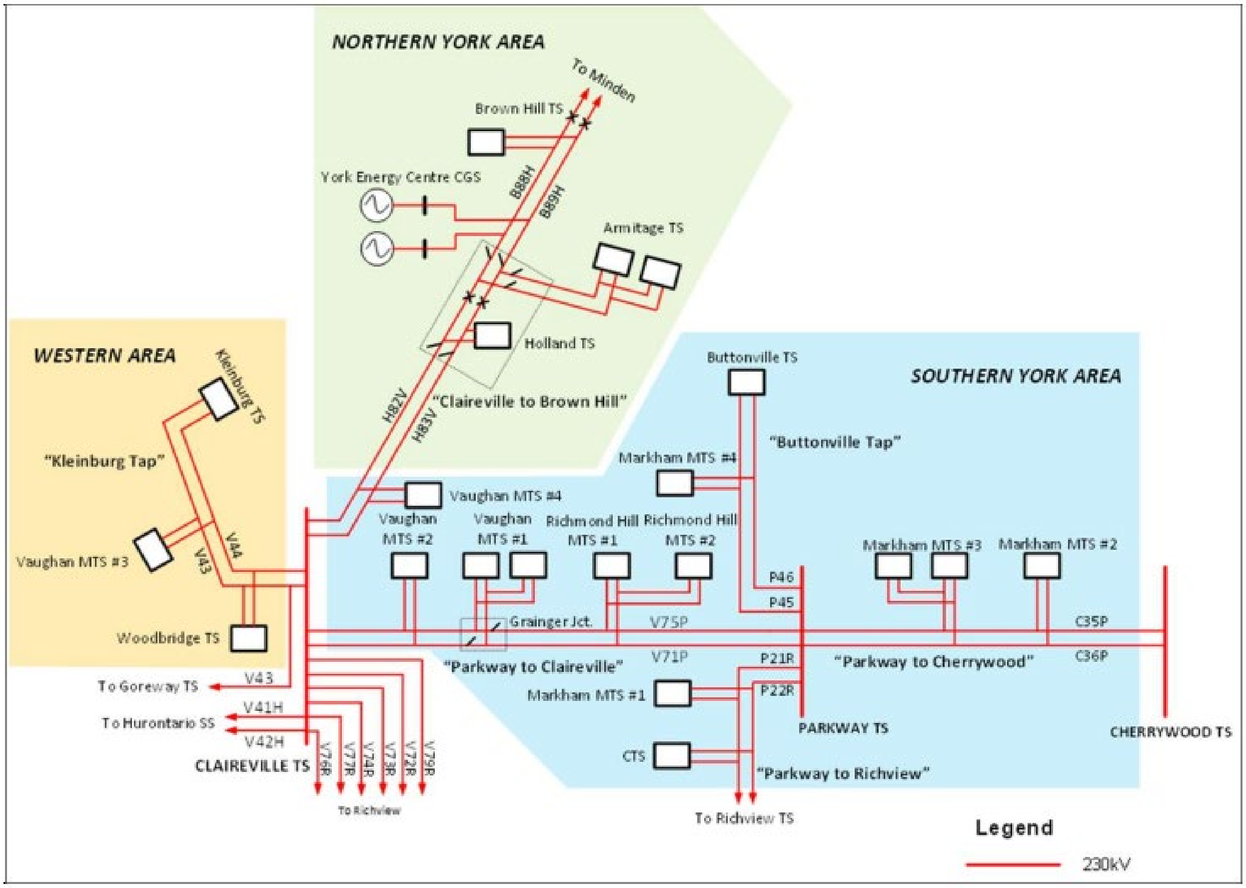

Figure 5.2.2 - 8 GTA North Transmission System[28]

The third GTA North Needs Assessment and Scoping Assessment were released in July 2023 and October 2023, respectively.

Participants in this RIP included IESO, Alectra Utilities, HONI (Distribution), Newmarket-Tay Power and Toronto Hydro.

The updated Needs Assessment Report reaffirmed the previously identified needs and identified additional needs, as illustrated in Table 5.2.2 - 2

[28] GTA North Region-NA 2023, Page 9

Table 5.2.2 - 2 GTA North Needs[29]

No	Need Date	Recommended Action Plan	Need Date
1	Kleinberg TS Area	Transfer load to Northern York TS	2027
2	Vaughan Area -Step down Transformation Capacity	Build new Vaughan MTS#6 and connect to 230kV circuit V43/V44	2027
3	Markham Area: New Customer Connection	Build New Toubner TS and line tap to 230kV circuits P45/46	2027
4	Richmon Hill Area: Step down Transformation Capacity	Build New Richmond Hill #3 MTS	2032
5	Load Restoration for 230kV circuits P45/46	To be reviewed in the next phase of this regional planning cycle	2027

B.1 York Sub-region

The York Sub-region encompasses the municipalities of Vaughan, Richmond Hill, Markham, Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville and Georgina, and is one of the fastest growing regions in Ontario.

As of 2025, two regional planning cycles have been completed and another regional planning cycle is underway for York Sub-region, with the next iteration of the IRRP anticipated to be completed and posted in the fourth quarter of 2025.

The Needs Assessment Report was finalized on 14, July 2023 and identified needs that require further regional coordination (refer to *Appendix H05 - GTA North Needs Assessment)*.

The most recent Scoping Assessment was completed in October 2023 (refer to *Appendix H06 - GTA North Scoping Assessment*).

The Scoping Assessment also identified new needs in York Region based on a new 10-year station-level demand forecast provided by the local distribution companies (LDCs), updated transmission asset condition information, and updated conservation and demand management (CDM) and distributed generation (DG) forecasts provided by the IESO. Some of these needs were determined through the Needs Assessment not to require further coordinated study through the regional planning process (refer to Table 5.2.2 - 3).

[29] GTA North Region-NA 2023, Page 16

Table 5.2.2 - 3 GTA North Needs That Do Not Require Further Coordinated Planning[30]

No	Station /Circuit	Description of Need
1	Woodbridge TS	End of life replacement of transformer T5
2	Toubner TS	Build new station in Markham
3	Vaughan MTS #6	Build new station in Vaughan

Many of the identified needs require a significant amount of planning, have a shared impact with other system assets or needs, or have the potential to be met with a combination of wires and non-wires alternatives. Therefore, the Needs Assessment concluded that these needs require further coordination (refer to Table 5.2.2 - 4).

Table 5.2.2 - 4 GTA North Needs That Require Further Coordinated Planning[31]

No	Location of Need	Station /Circuit	Description of Need
1	Kleinburg	Station Capacity	Significant new load is forecast to connect at the 44kV bus in the 2023-2024 period, exceeding its capacity
2	Markham	Station Capacity	Markham area stations are expected to exceed their capacities by 2028
3	Buttonville Tap	System Capacity	Circuits supplying Markham MTS #4 and Buttonville TS are expected to exceed their capacities by 2028
4	Northern York Region	Station Capacity	Northern York region is expected to reach the area's stations' capacity by 2027
5	Vaughan	Station Capacity	Vaughan area stations are expected to exceed their capacities by 2030
6	Richmond Hill	Station Capacity	Richmond Hill area stations are expected to exceed their capacities by 2032
7	Claireville to Brown Hill transmission corridor	System Capacity	Loading on the Claireville TS x Brown Hill TS corridor is expected to exceed its capacity by the early 2030s.

[30] GTA North (York Region) Scoping Assessment Outcome Report Oct 2023, Page 9
[31] GTA North (York Region) Scoping Assessment Outcome Report Oct 2023, Page 9

No	Location of Need	Station /Circuit	Description of Need
8	Kleinburg Tap transmission corridor	Load Restoration	Inability to restore customer loads within the timelines established by planning criteria following a major system disturbance
9	Claireville to Brown Hill transmission corridor	Load Restoration	Inability to restore customer loads within the timelines established by planning criteria following a major system disturbance.
10	Buttonville tap transmission corridor	Load Restoration	Inability to restore customer loads within the timelines established by planning criteria following a major system disturbance.
11	Parkway to Claireville Transmission corridor	Load Security	The loss of this line can result in an interruption to over 600MW of customer load, which is more than permitted by planning criteria

The Scoping Assessment concludes that:

- IRRP is to be undertaken for York Region
- The IRRP Technical Working Group will include the IESO, Alectra Utilities, Newmarket-Tay Power, Hydro One Distribution, and Hydro One Transmission; and
- Other LDCs in the region will be informed of any needs or solutions that may affect their facilities or customers
- The IRRP will co-ordinate its findings with the GTA Bulk Supply Study, and vice-versa

Given the significant scope of the study, the IESO-led TWG determined that it would take the full 18-month timeline for completion of the study. The regional planning study is ongoing.

Based on the identified needs in NA and SA, and current progress of the IRRP, Alectra Utilities will be required to make investments in station expansions in Vaughan (VTS#6, VTS#5), Richmond Hill (RHTS#3) and Markham (MTS#5, MTS#6) during and beyond the DSP period. Further information on planned station investments can be found in *Appendix B13 - Stations Capacity*.

C GTA West

The Greater Toronto Area (GTA) West Region includes Brampton, South Caledon, Halton Hills, Mississauga, Milton, and Oakville. It has been further divided for planning purposes into a Northern Sub-region and a Southern Sub-region. Portions of Alectra Utilities' service territory fall within the Northern Sub-region (i.e. Brampton) as well as the Southern Sub-region (i.e. Mississauga), as shown in Figure 5.2.2 - 9.

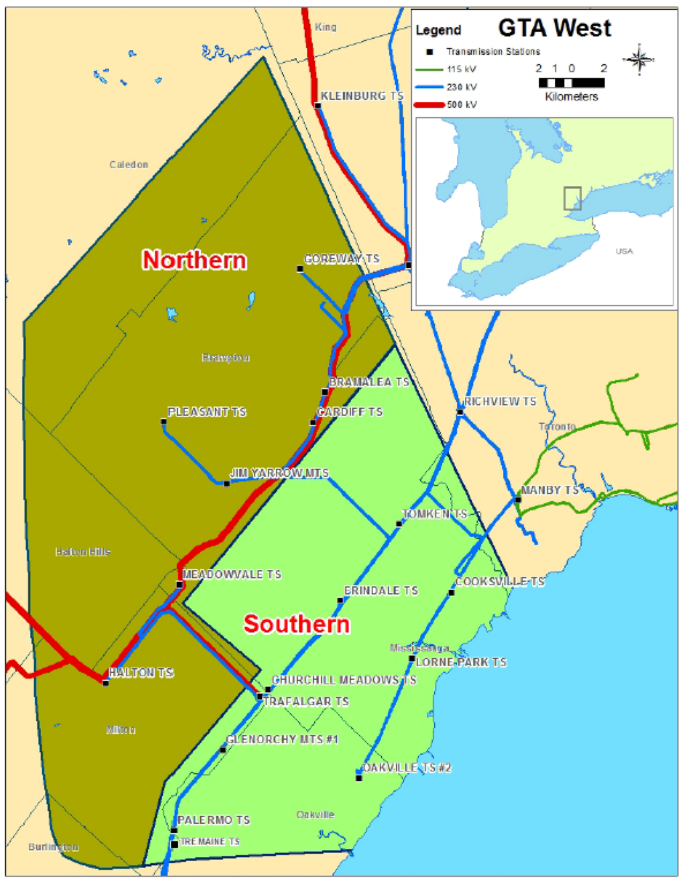

Figure 5.2.2 - 9 GTA West Region[32]

Bulk electricity in the region is supplied by the Burlington TS from the west, the Claireville TS from the north, the Richview TS and Manby TS from the east, and 500/230kV autotransformers at the Trafalgar TS, and distributed by a network of 230kV transmission lines and 21 transformer

[32] GTA West -RIP 2022, Page 12

stations. Local generation in the region includes two gas fired plants, Sithe Goreway generating station (827MW rated capacity) and TCE Halton Hills generating station (555MW rated capacity).

The latest Needs Assessment and Scoping Assessment provides a consolidated summary of the needs identified for both the Northern Sub-region and Southern Sub-region that make up the GTA West Region (refer to *Appendix H07 - GTA West Needs Assessment).*

The Transmission System single line diagram to cover the GTA West areas is shown in Figure 5.2.2 - 10.

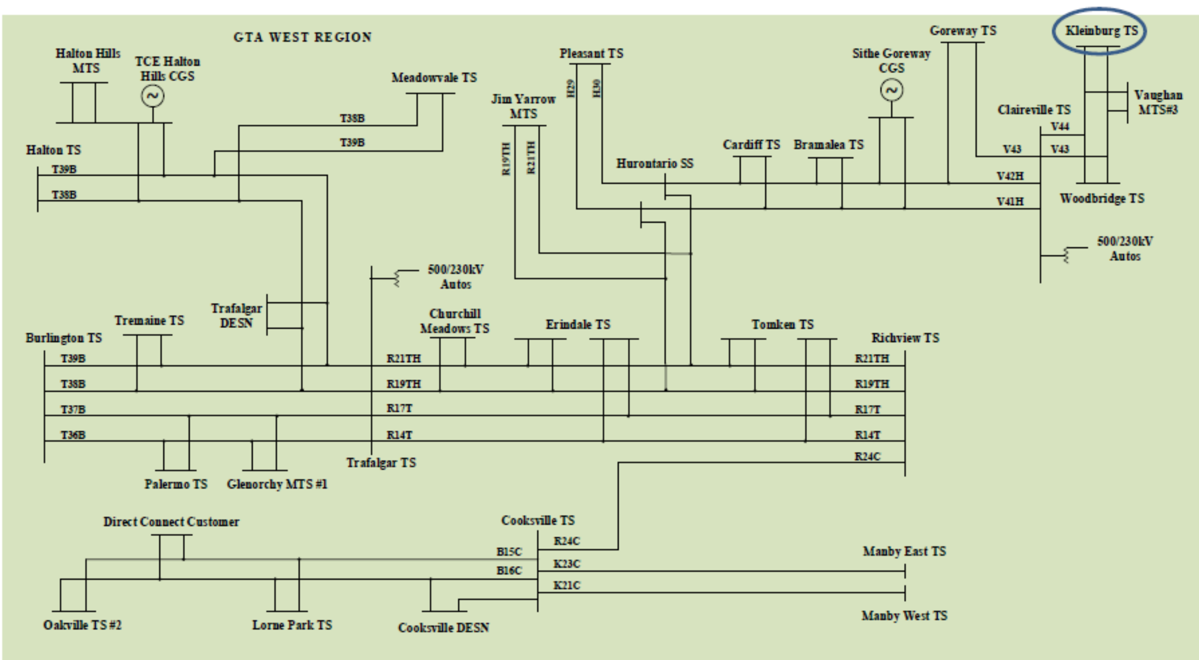

Figure 5.2.2 - 10 Transmission System of GTA West

The latest RIP was finalized in February 2022 by the TWG comprised of staff from IESO, HONI (Transmission), Burlington Hydro, Halton Hill Hydro, Alectra Utilities, HONI (Distribution), Milton Hydro and Oakville Hydro.

Figure 5.2.2 - 11 illustrates the GTA West Region load forecast from 2022 to 2040 from the RIP report. The forecast represents the sum of the load for the 21 transformer stations at the peak and was used to determine the need for additional transmission reinforcements.

The coincidental peak was forecast to increase from approximately 3,200MW in 2022 to 4,100MW in 2040.

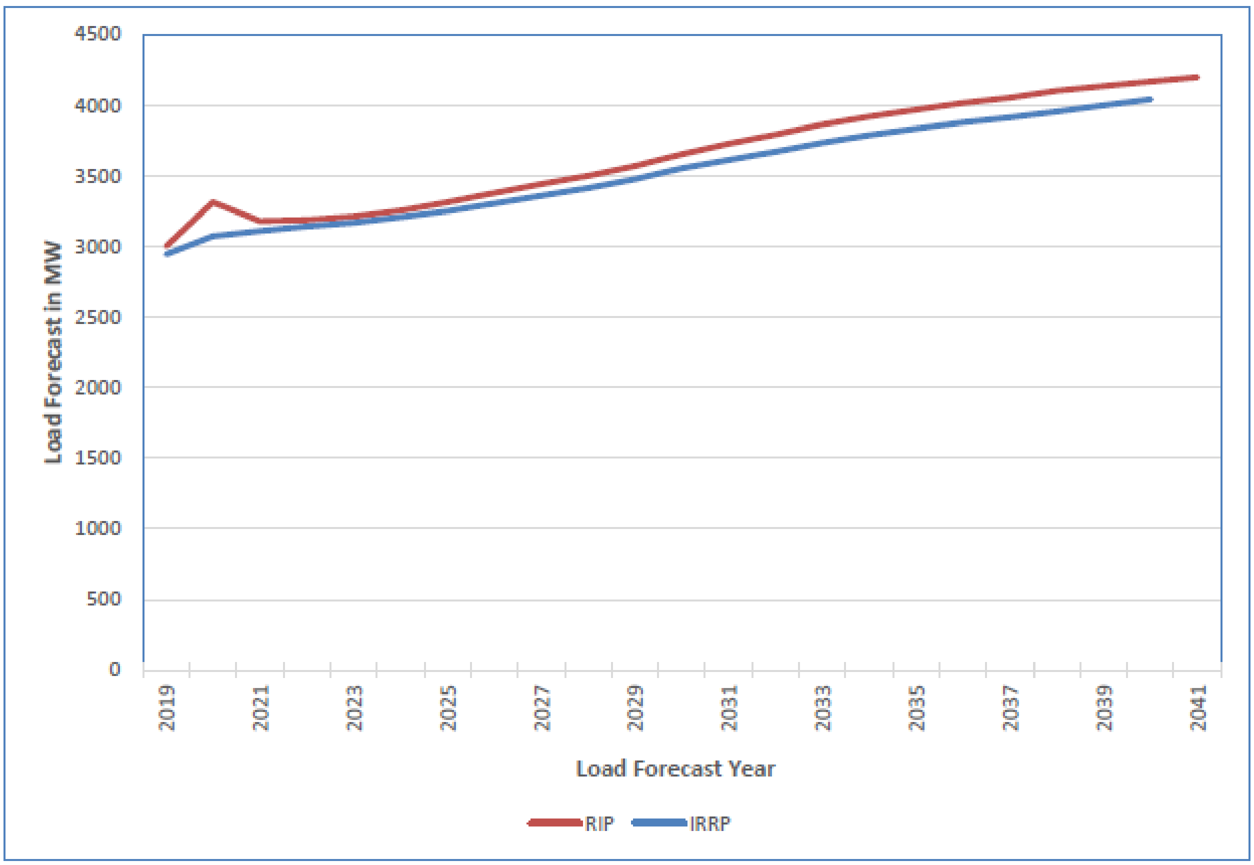

Figure 5.2.2 - 11 GTA West Region Non-coincident Net Summer Peak Load Forecast until 2040[33]

[33] GTA West -RIP, Page 23

The major infrastructure investments planned for the GTA West Region over the near-term and medium-term (2021-2031), as identified in the RIP, are illustrated in Table 5.2.2 - 5.

Table 5.2.2 - 5 GTA West Needs[34]

Project
Bramalea TS: Replace Transformers T3 and T4
Tomken TS: Replace Transformers T1 and T2
Lorne Park: Replace Transformer T2
Palermo TS: Refurbish and upgrade Transformers T3 and T4 and add new 27.6kV yard
Hurontario TS x Pleasant TS: Reconductor circuits H29/H30 with higher ampacity conductor

Out of the above stated needs, Alectra Utilities is coordinating with HONI to increase the capacity of H29/H30, as shown in Figure 5.2.2 - 10. This project is included in the DSP, refer to *Appendix B13 – Stations Capacity*.

The new regional planning cycle commenced in 2024. The GTA West Needs Assessment concluded in August 2024. The Scoping Assessment was completed in November 2024 and is provided in *Appendix H08 - GTA West Scoping Assessment.* The IRRP process began in January 2025.

The Needs Assessment identified new system needs in the GTA West Region using the updated 10-year station level demand forecast. The TWG determined that several identified needs require no further coordinated study. These are listed in Table 5.2.2 - 6. Needs requiring further coordination are listed in Table 5.2.2 - 7.

[34] GTA West -RIP 2022, Page 6

Table 5.2.2 - 6 GTA West That Do Not Require Further Coordination[35]

No	Need	Recommendation
1	Bramalea TS: T3/T4	Station Capacity
2	Lorne Park TS	Station Capacity
3	Pleasant TS: T1/T2	Station Capacity

Table 5.2.2 - 7 GTA West That Require Further Coordination[36]

No	Need	Timing
Halton TS	Station Capacity	2026
Bramalea TS: T1/T2	Station Capacity	2030
Erindale TS: T1/T2	Station Capacity	2030
Cardiff TS	Station Capacity	2030
Cooksville TS	Station Capacity	2030
Pleasant TS: T5/T6	Station Capacity	2026
Jim Yarrow TS: T1/T2	Station Capacity	2030
Goreway TS: T5/T6	Station Capacity	2026
T38B/T39B	Load Security	2029
T38B/T39B	System Capacity	TBD

The IRRP is underway and will be completed in 2026. Based on the Needs and Scoping Assessment and Alectra Utilities' own capacity planning analysis, Alectra Utilities will be required to make investments in stations and transmission expansions in Brampton (i.e. New Goreway TS and the New Heritage TS), and in Mississauga (i.e. Lakeview TS and Gateway TS) during and beyond the DSP period. Further information on planned station investments can be found in *Appendix B13 - Stations Capacity (Section 3.2.2).* Alectra Utilities has also further identified a transformation need at the distribution level (i.e. Webb MS) which has been included in the same section.

[35] *Appendix H08 GTA West Scoping Assessment*, Page 9
[36] *Appendix H08 GTA West Scoping Assessment*, Page 15

D Toronto Region

The Toronto Region includes the area defined by the municipal boundary for the City of Toronto. The Technical Working Group consisted of staff from IESO, HONI (Transmission), Toronto Hydro, Alectra Utilities, Elexicon Energy and HONI (Distribution).

A new regional electricity planning cycle has begun for the Toronto Region that will examine local growth and future electricity needs. The IESO developed a Scoping Assessment in March 2023 following the completion of the Needs Assessment published by Hydro One in December 2022. Refer to *Appendix H09 - Toronto Region Needs Assessment* and *Appendix H10 - Toronto Region Scoping Assessment*.

Alectra Utilities is involved in the Toronto Region Scoping Assessment because several distribution feeders from stations with this region supply the municipalities of Mississauga, Markham and Vaughan, as illustrated in Table 5.2.2 - 8.

Table 5.2.2 - 8 Toronto Region Feeders Supplying Alectra Utilities

TS Name	Number of 27.6kV Feeders
Agincourt TS	2
Leslie TS	3
Fairchild TS	3
Finch TS	2

Alectra Utilities confirms that the Toronto Region IRRP does not require investments at the regional level in this DSP.

E Burlington–Nanticoke Region

The Burlington-Nanticoke Region is divided for planning purposes into four sub-regions as shown in Figure 5.2.2 - 12[37].

1. Brant
2. Bronte
3. Greater Hamilton

[37] Burlington to Nanticoke IRRP Dec 18, 2014, Page 1

4. Caledonia-Norfolk

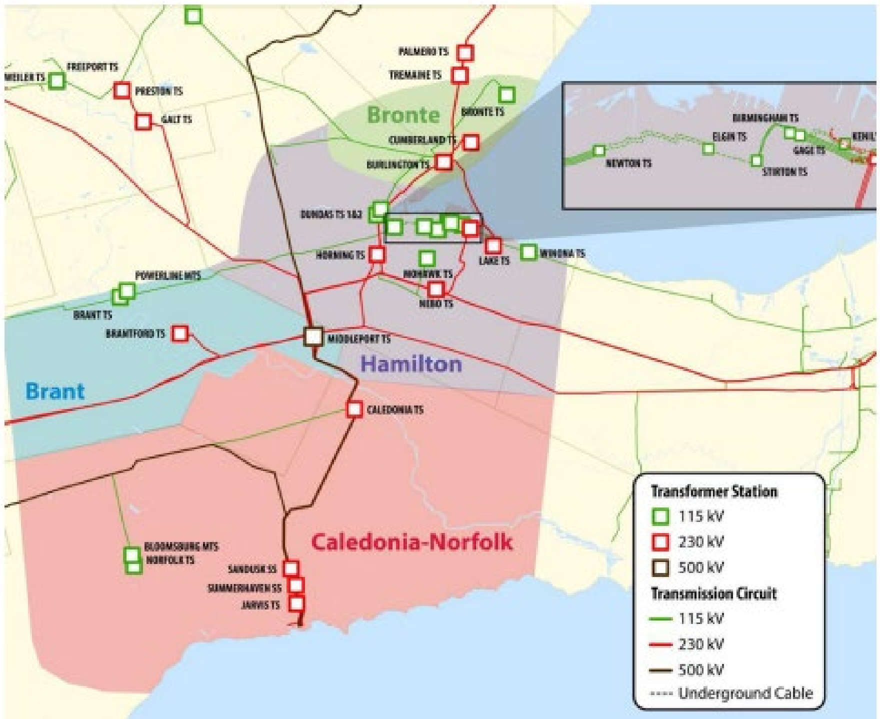

Figure 5.2.2 - 12 Burlington-Nanticoke Area

Alectra Utilities' service territory does not include any portions of the Brant, Bronte, and Caledonia Sub-regions, so it does not participate in regional planning process for those areas.

The Technical Working Group consisting of staff from IESO, HONI (Transmission), Alectra Utilities, GrandBridge Energy, Burlington Hydro and HONI (Distribution), and Oakville Hydro participated in developing the latest IRRP report.

The Needs Assessment and Scoping Assessment report is provided in *Appendix H11 - Burlington-Nanticoke Area Needs Assessment* and *Appendix H12 - Burlington-Nanticoke Area Scoping Assessment* respectively. The latest IRRP was published in December 2024 and included in *Appendix H13 - Burlington-Nanticoke Area IRRP however Hamilton Sub region was not studied in the IRRP*.

E.1 Hamilton Sub-region

This sub-region encompasses the City of Hamilton and surrounding areas. A map of the sub-region is shown in Figure 5.2.2 - 13.

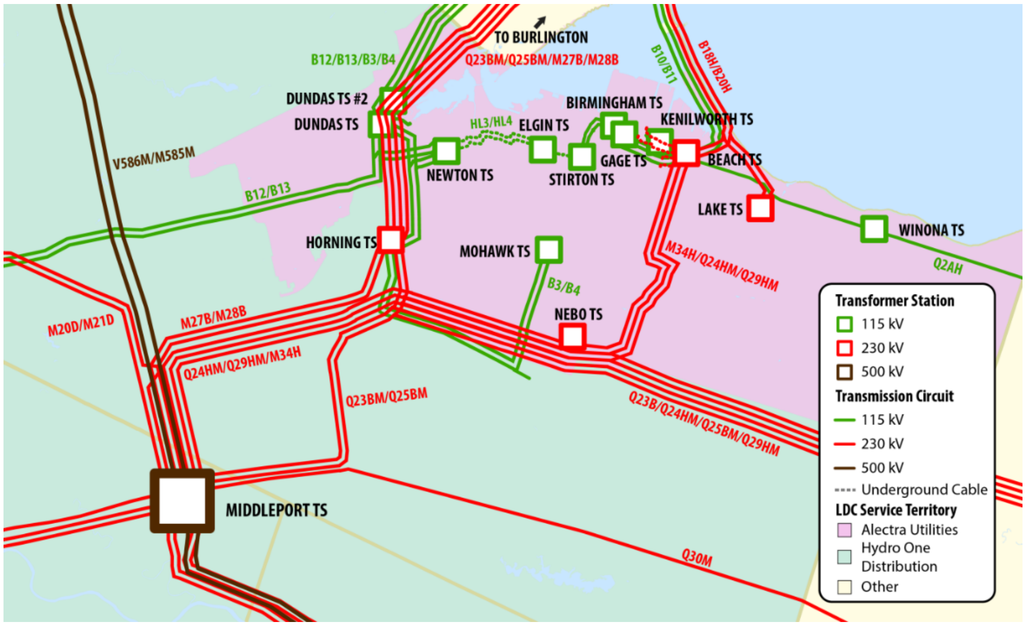

Figure 5.2.2 - 13 Hamilton Sub-region[38]

Some of this sub–region's electrical infrastructure is among the province's oldest. Electricity supply to the sub-region is as follows:

- The East Hamilton 115kV area, which includes four 115kV step-down stations (i.e. Birmingham TS, Kenilworth TS, Stirton TS and Winona TS) and a customer owned Transformer station supplied from the 230/115kV autotransformers at Beach TS.
- The Burlington TS 115kV area, which includes Dundas TS, Dundas #2 TS, Elgin TS, Gage TS, Mohawk TS, Newton TS and one customer-owned CTS supplied from the 230/115kV autotransformers at Burlington TS.
- A 230kV area, which includes Beach TS, Horning TS, Nebo TS, Lake TS and two customer owned stations supplied from 230kV circuits connecting into Beach TS and Burlington TS

In the Hamilton Sub-region, 10 out of 19 Dual Element Spot Network (DESN) stations are forecast to exceed their station capacity within the planning horizon. Notably six of these DESN stations

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[38] Hamilton Sub Region IRRP 2019, Page 9

(i.e. Dundas TS, Dundas 2 TS, Mohawk TS, Nebo TS (T1/T2) and (T3/T4) and Newton TS) are identified with station capacity needs with a near-term or medium-term timeframe

Table 5.2.2- 9 Greater Hamilton Sub-region Needs 2024[39]

No.	Needs	Timing Need
1	Dundas 2 TS – Capacity Need	2023
2	Nebo TS (T1/T2) – Capacity Need 27.6kV	2023
3	Nebo TS (T3/T4) – Capacity Need 13.8kV	2023
4	Dundas TS – Capacity Need	2025
5	Mohawk TS – Capacity Need	2026
6	Newton TS – Capacity Need	2031
7	Lake TS (T1/T2) – Capacity Need	2035
8	Elgin TS – Capacity Need	2037
9	Horning TS – Capacity Need	2038
10	Beach TS (T5/T6) – Capacity Need	2042
11	Hamilton 115kV Subsystem – Supply Capacity Needs	Med-term**
12	Beach TS – 230/115kV Auto Transformers EOL	Med-term
13	Birmingham TS – DESN Transformers and Switchgear EOL	Med-term
14	Gage TS(T8/T9)– DESN Transformers and Switchgear EOL	Med-term
15	Lake TS – DESN Transformers and Switchgear EOL	Med-term
16	Nebo TS (T3/T4) – DESN EOL	Med-term
17	Dundas TS – DESN EOL	Long-term

These station capacity needs were identified in the IRRP; the IESO led TWG established that those needs will be addressed in the Hamilton Addendum starting in 2025.

Based on the Needs and Scoping Assessment and on Alectra Utilities' own capacity planning analysis, Alectra Utilities will be required to make investments in station expansions in the

[39] Burlington Nanticoke Integrated Regional Resource Plan – IRRP 2024 Page 36, 38, 39
**- EOL – End of Life as defined by HON*
***- Will be addressed in Addendum*

Hamilton Sub-region (i.e. Newton TS and New Station Hamilton SouthWest) during the DSP period. Further information on planned station investments can be found in *Appendix B13 - Stations Capacity (Section 3.2.3).*

F Niagara Region

The Niagara Region includes the Cities of Niagara Falls, Port Colborne, St. Catharines, Thorold, Welland; the Towns of Fort Erie, Grimsby, Lincoln, Niagara-on-the-Lake, Pelham; and Townships of Wainfleet, and West Lincoln as illustrated in Figure 5.2.2 - 14. Alectra Utilities' service territory includes the City of St. Catharines.

The IRRP of Niagara region was completed in December 2022 and Hydro One published the RIP of this region in July 2023, which are provided in *Appendix H14 - Niagara Region IRRP* and *Appendix H15 - Niagara Region RIP*.

Figure 5.2.2 - 14 Niagara Region Map[40]

[40] *Appendix H17 Niagara -RIP*, 2023

Table 5.2.2 - 9 summarizes needs identified in the latest RIP.

Table 5.2.2 - 9 St. Catharines Sub-region Needs 2024[19]

No.	Needs	Need Date per RIP
A6	Carlton TS – Capacity Transfer Load to Bunting TS	2029
B2	Glendale TS – T1/T2 DESN EOL*	2027
B3	Carlton TS – LV Switchgear EOL*	2025
B4	Bunting TS – T1/T2 DESN EOL*	2029
B6	Vansickle TS – LV Switchgear EOL*	2032

**- EOL – End of Life as defined by HON*

HONI reviewed the condition of autotransformers and power transformers in the region and proposed several sustainment initiatives in the RIP report. The review identified secondary voltage switchgear at Carlton TS, which serves Alectra Utilities' St. Catharines customers, as end-of-life. Hydro One plans to replace this switchgear by the end of 2025 and is executing the project.

Alectra Utilities will coordinate investments with the Carlton TS upgrade to align forecast development in the St. Catharines' downtown core. Consolidation of the St. Catharines downtown core supplies will upgrade sub-capacity feeders to industry-standard, increasing capacity and reliability. Alectra Utilities is investing to enable an internal system load transfer from Carlton TS to Bunting TS to release capacity at Carlton TS. Alectra Utilities will monitor increasing demand in the development in the downtown core to inform future feeder expansions (refer to *Appendix B12 - Lines Capacity* for information on St. Catharines' Downtown feeder consolidation project).

G Kitchener, Waterloo, Cambridge and Guelph Region

The Kitchener, Waterloo, Cambridge and Guelph (KWCG) Region is located to the west of the GTA in Southwestern Ontario. The region includes the Cities of Kitchener, Waterloo, Cambridge and Guelph, as well as portions of Perth and Wellington counties and the townships of Wellesley, Woolwich, Wilmot, and North Dumfries. Alectra Utilities' service territory includes Guelph and Rockwood.

The Needs Assessment for the KWCG Region was completed in April 2024. Table 5.2.2 - 10 summarizes the identified needs.

Table 5.2.2 - 10 Guelph Needs in the 2024 Needs Assessment[41]

No.	Needs	Timing Need
1	Campbell TS (T3/T4) – Capacity DESN	2026
2	Cedar TS (T7/T8) – Capacity DESN	2025
3	Cedar TS (T1/T2) – Capacity DESN	2031
4	Cedar TS (T7/T8) – DESN EOL*	2034+
5	Campbell TS – Breakers & Component EOL*	2032

**- EOL – End of Life as defined by HONI*

The TWG determined that the needs require further regional planning.

The (NA) and (SA) are included in *Appendix H16 - KWCG Needs Assessment* and *Appendix H17 - KWCG Scoping Assessment*.

The KWCG IRRP is in development, and results will be published in 2025.

Based on the Needs and Scoping Assessment and on Alectra Utilities' own capacity planning analysis, Alectra Utilities will be required to make investments in station capacity expansions in the Guelph area (i.e. Campbell TS Expansion) during the DSP period. Further information on planned station investments can be found in *Appendix B13 - Stations Capacity*.

5.2.2.10 Summary of Investments Driven by Regional Planning

Table 5.2.2 - 11 illustrates the near-term investments that Alectra Utilities plans to undertake as a result of coordinated distribution system planning through Regional Planning processes. Table 5.2.2 - 11 includes investments for projects and needs identified in completed RIPs, IRRPs, and Needs Assessment and Scoping Assessments in which Alectra Utilities participates.

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[41] KWCG Needs Assessment – NA 2024, Page 8

Table 5.2.2 - 11 Summary of Regional Planning Activities

Region or Sub-Region	Near Term Actions Identified	Project Reference	$MM (2027-2031)
York	Build Markham MTS#5	101488	10.0
	Build Vaughan Station (VTS#6)	152484	1.3
	Build MTS#5 for VMC	152762	14.9
	Build Richmond Hill TS3	152758	56.5
	Build Markham TS#6	152846	2.8
GTA West	Reconductoring Pleasant H29/H30 circuits	152723	5.0
	230kV UG Transmission Line for Heritage TS	152883	53.3
	New Goreway TS	152845	50.1
	New Heritage TS	152847	13.3
	Lakeview TS	152889	50.1
	Gateway TS	152888	2.8
Hamilton Sub Region	New -Station Hamilton South West	152850	19.8
	Newton TS (Capacity)	152493	25.5
KWCG	Campbell TS Metal Clad Expansion	151147	25.5

The investments identified in the DSP are consistent with the completed regional plans. The needs identified through Alectra capacity analysis and the needs identified in the Needs Assessment and Scoping Assessment completed for regional planning are consistent. The IRRP activities for the GTA North, GTA West, KWCG regions are ongoing, and the results are expected to be published in 2026. The IRRP study for the Hamiton region is scheduled to start in November 2025. Based on the IRRP activities completed to date; Alectra Utilities confirms consistencies with the investments identified in the DSP.

5.2.3 Performance Measurement for Continuous Improvement

To facilitate continuous improvement in the implementation of activities planned in this DSP and to remain responsive to customer needs, priorities, and preferences, Alectra Utilities has developed 12 DSP-specific performance measures. These performance measures are meant to supplement the metrics that Alectra Utilities already tracks and reports through the OEB's Electrical Distributors Scorecard process, for a total of 41 unique measures to be tracked by Alectra Utilities. As a regulated entity, Alectra Utilities is obligated to provide a wide variety of reporting, which includes the OEB Scorecard and Reporting and Record Keeping Requirements (RRR), Electrical Safety Authority Regulation 22/04 annual audits and serious Electrical Incident Reporting. Beyond that, Alectra Utilities is providing additional performance measures specific for the Distribution System Plan as described in this section.

Service Reliability and Quality metrics are provided in OEB Appendix 2-G, filed under *Exhibit 1B* of this application. Alectra Utilities meets or surpasses the OEB's minimum standard in nine metrics. Alectra Utilities had declining (worsening) trends in only two metrics: Telephone Accessibility and Telephone Call Abandon Rate (TCAR). In 2023 and 2024, Alectra Utilities' Customer Service Representatives (CSRs) received 606,388 and 636,233 customer calls, respectively. CSRs answered 53.4% of all calls within 30 seconds in 2023 and 29.8% in 2024. Alectra received a higher than forecast volume of calls primarily attributed to arrears management and collections activities. Calls of this nature are relatively complex and have a high Average Handle Time (AHT). Alectra Utilities has responded to these challenges by enhancing Contact Centre resource support through outside service providers and redesigning the Interactive Voice Response (IVR) menus to streamline calls and more efficiently route calls to the appropriate agents. Alectra Utilities continuously monitors call statistics and workforce availability to best align staffing levels to call arrival rates. Furthermore, Alectra Utilities has started to mitigate the service level decline through the introduction of targeted messaging to reference self-service options on its website, such as forms for customer move requests (start/stop service), preauthorized payment registration, and rate plan changes, which accounted for approximately 50% of these customer interactions.

The increase in call volumes and call handling times has resulted in an increase (worsening) in the TCAR. In 2023 and 2024, the TCAR was 11.5% and 18.2%. To address these worsening metrics, Alectra Utilities has included capital investments in Web chatbot, AI chatbot, Intelligent Virtual Assistant and Agent Assist. For details on these investments refer to *Appendix B14 – Enabling Resilient & Modernization* under Customer Service Technologies. These investments also link to productivity efficiencies found in *Exhibit 4, Tab 2, Schedule 7, Section 4.1.1 Customer Care, Subsection 4.2 Productivity*.

For discussion regarding the performance measures for continuous improvement established by Alectra Utilities in its prior DSP, from EB-2019-0018, refer to *Appendix P - 2019 Performance Measures*. In considering Alectra Utilities' performance relative to the measures established in its prior DSP, it is important to recognize the context in which those measures were established. As explained in *Chapter 5.4.1.2*, the prior DSP was the first since the company was formed and was submitted as part of an application (EB-2019-0018) that contemplated an investment roadmap averaging $291MM per year. Ultimately, available funding through base rates supported only $246MM of capital investment per year. As such, over the 2020-2024 period, Alectra Utilities implemented its capital investment plan guided by trade-offs between needs and available funding, supplemented by approximately $40MM of ICM funding over the period.

5.2.3.1 Performance Measurement Framework

Alectra Utilities has outlined 12 performance measures specifically focused on this DSP. These performance measures will track Alectra Utilities performance in implementing the plan, with a focus on System Renewal investments, which account for two-thirds of the capital funding. The DSP Performance Measures are detailed in Table 5.2.3 - 1 and the performance relative to these measures is further discussed in *Section 5.2.3.2*.

1 **Table 5.2.3 - 1 DSP Performance Measures**

DSP Performance Measures	Description
Cost Control - Planned Capital (Actual vs Budget): Planned Capital (Actual Spend vs. Budgeted Spend (in dollars))	Prudently invest in and maintain assets to provide sustainable value through the optimal allocation of resources in response to relevant risks, compliance requirements and performance targets.
Infrastructure Renewal: Alectra Utilities would have replaced the following assets, under the multi-year renewal investments by end of 2031: Poles: 5,256 Transformers: 4,771 Switches: 255 Switchgear: 344 Cable Replacement (KM): 381	Ensuring asset replacement targets for units installed (for various asset types) is completed as planned, ultimately resulting in reliability, safety, and other risk improvements and system resiliency.
Infrastructure: Total AMI 2.0 Meters installed	Ensure the total number of AMI 2.0 meter installs by the end of 2031 is 950,000.
Enabling Resilience and Modernization: In service of automated devices on the distribution system	Increase distribution automation penetration to enhance customer service, reliability, system resilience and increase system telemetry.
Meeting Growing Electricity Demand: Increased Station Capacity	Increased station capacity to meet the increased demand from the communities we serve.
Infrastructure: Vehicle Availability	Ensure Fleet vehicles are available to execute work and respond to reactive needs in an efficient manner.
System Reliability: SAIDI – Excluding MED Customer Hours of Interruption (CHI) due to Failed Equipment	Enhance operational effectiveness and system performance in alignment with Alectra Utilities' Plans to maintain or better reliability for customers.

5.2.3.2 Performance Metrics

The following section describes the DSP performance metrics, including details on each performance objective and the 2025-2031 target/outcome that Alectra Utilities plans to achieve.

A Cost Control – Planned Capital (Actual vs. Budget)

Measuring planned capital expenditures relative to actual capital expenditures enables Alectra Utilities to track the total expenditure of those capital investments within its control in terms of scope, schedule, and cost. Planned Capital is defined as investments in the System Renewal and System Service investment categories, but excludes Reactive Capital investments as reactive work is demand-driven and thus beyond the control of Alectra Utilities.

The Cost-Control performance measure tracks the cumulative expenditure of planned capital investments relative to the plan as outlined in this DSP over the 2027-2031 period. Alectra Utilities' DSP specific performance metric for cost control was developed based on the investment needs within this DSP and associated funding approval.

Alectra Utilities plans to achieve an average of 100% (+/- 5%) planned capital expenditure 5-year average within 95-105% during the 2027-2031 Rate Period. Alectra Utilities plans to achieve an average of 100% (+/- 5%) planned capital expenditure during the 2027-2031 Rate Period. Table 5.2.3 - 2 summarizes these details for the 2027-2031 performance metric on cost control – actual vs. budget.

Table 5.2.3 - 2 Planned Capital Actual vs. Budget Performance Target

2027-2031 Performance Measure	Target
Cost-Control: Planned Capital - Actual vs. Budget from the Annual Planned Project List	100% (+/- 5%)

B Infrastructure Renewal

Pole Renewal, Switch Renewal, Switchgear Renewal, Transformer Renewal and Cable Renewal represent 59% of all System Renewal expenditures. These distribution assets are essential elements of a distribution system. Alectra Utilities has a significant volume of these assets in deteriorated condition, impacting customer reliability and increasing various risks and require replacement (refer to *Chapter 5.3.2 Overview of Assets Managed* for details on asset condition). To demonstrate Alectra Utilities' commitment to replacing deteriorated assets, Alectra Utilities has developed a DSP specific performance metric to ensure that the execution of its investments manages the risk of asset deterioration.

Table 5.2.3 - 3 outlines the units that will be renewed and placed in service over the 2027-2031 period. The targets are set based on the application being approved as proposed. Variations to the proposals will impact the target set for asset replacement quantities.

Table 5.2.3 - 3 Infrastructure Asset Renewal Performance Target

2027-2031 Performance Measure	Target
By the end of 2031 Alectra Utilities would have replaced the following assets under the associated investments:	Poles Renewal: 5,256
	Transformers Renewal: 4,771
	Switch Renewal: 255
	Switchgear Renewal: 344
	Cable Replacement: 381KM

C Infrastructure: AMI 2.0 Meters Installed

Alectra Utilities has a significant investment required in metering; this is discussed in detail in *Appendix B06 - Network Metering*. To highlight accountability to customers, Alectra Utilities plans to implement a performance measure tracking total meters installed. This provides tracking and accountability to customers to illustrate the link between funding spent and meters installed. Table 5.2.3 - 4 provides the total installed meter quantities Alectra Utilities plans to achieve by the end of 2031.

Table 5.2.3 - 4 Infrastructure AMI 2.0 Total Meters Installed

2027-2031 Performance Measure	Target
AMI 2.0 Total Meters Installed by the end of 2031	950,000

D Distribution System Modernization: Distribution Automation

The following target aligns with three points from customer preferences expressed during the Customer Engagement that Alectra Utilities undertook in preparing the DSP. The first is reliability as a top priority. The second is a reduction of outages from major events and lastly the third is support of investments on enabling grid resilience and modernization. To this end, Alectra Utilities has developed a Distribution Automation target based on the installation of additional automated devices. Distribution Automation is an effective asset in managing customer reliability. In 2023 and 2024, automation helped reduce SAIDI by 14.21 minutes and 15.51 minutes respectively. Without automation in place, customers would have seen much longer duration outages. Alectra Utilities defines additional automated device installations on sites where either none previously existed, or the upgrade to an automated unit during a renewal of a manual switch/switchgear.

Table 5.2.3 - 5 provides the yearly target Alectra Utilities plans to achieve; a total of 530 automated devices by the end of 2031.

Table 5.2.3 - 5 Automated Devices Installed

2027-2031 Performance Measure	Target				
	2027	2028	2029	2030	2031
In service of automated devices on the distribution system	100	100	110	110	110

E Meeting Growing Electricity Demand: Added Station Capacity

Alectra Utilities plans to invest in new stations to supply housing and business developments that are occurring within its communities, as identified in *Chapter 5.3.2 (Section 5.3.2.1 B.2)*. The added capacity is critical to allow new customers to connect to the system and handle existing customer load growth. The following metric is proposed to track the outcomes expected to be delivered to customers. The target for additional station capacity by 2031 is to add 685 Mega Volt-Amp (MVA) to the system to ensure that communities and customers' electricity needs are adequately served.

Table 5.2.3 - 6 Added Station Capacity Target

2027-2031 Performance Measure	Target (End of 2031)
Added Station Capacity	685 MVA

F Renewing and Replacing Infrastructure: Fleet Availability

To align increased investment in fleet assets with measurable outcomes, Alectra Utilities has developed a performance metric to track fleet availability. Fleet 'availability' is defined as the time a vehicle is ready and fit for use by staff. Alectra Utilities historical pacing of fleet renewals has been well below the rate of deterioration. Given the necessary capital work that is planned, Alectra Utilities has a need for fleet vehicles to support operational requirements. Additionally, the changes in pole classes mandated by Canadian Standards Association (CSA) result in Alectra Utilities requiring fleet trucks to handle those higher class and taller poles as necessary for installation and maintenance of the assets. Similarly, transformers are also increasing in size and weight as customers demand more power, due to transition to EVs, or heat pumps, or intensification with large high-rises which results in larger transformers. Larger transformers weigh more and put additional stress on vehicles, which previously was not common.

Alectra Utilities plans to ensure that the fleet availability of operations vehicles (e.g. Single Bucket, Double Bucket, Radial Boom Derrick, Lead Hand/Supervisor Pickups, Underground Vans, P&C Vans, Substation Vans) will exceed 90% each year from 2027 to 2031 (refer to Table 5.2.3 - 7).

Table 5.2.3 - 7 Fleet Availability Performance Targets

2027-2031 Performance Measure	Target (Yearly)
Fleet Availability	> 90%

Setting this target will ensure that Alectra Utilities has fleet vehicles ready to perform both planned work, as well as reactive work and emergency after-hours work, which significantly impacts customers.

G Service Quality and Reliability

The metrics Alectra Utilities has proposed directly align with customers' needs and priorities outlined in the first phase of customer engagement (refer to *Exhibit 1, Tab 5, Schedule 2 Application-Specific Customer Engagement*). Specifically customers had reliability as one of the top three priorities. (For a full listing of historical reliability data and Major Event Days that occurred since the last DSP, refer to *Appendix L - Historical Reliability Data* and *Appendix M - Major Event Days (2020-2024)* respectively.)

Approximately two-thirds of the total capital investment plan in this DSP is directed to infrastructure renewal. A key focus is improving reliability (SAIDI and SAIFI) with emphasis on customers experiencing poor reliability. Historical examples include areas like Valleywood Drive in Markham which saw seven outages just from cable failures in one year. Another example was the Sir John's Homestead neighbourhood in Erindale. Over three years those customers experienced nine failures well above the average of one per year.

Improvements to local level customer reliability will be achieved through the careful planning of renewing deteriorated assets that will provide customers with the greatest reliability impact. Although Alectra Utilities will monitor several reliability measures (e.g. SAIDI, SAIFI, CHI, CI etc.), the proposal is for two DSP-specific performance measures to track these outcomes: SAIDI and Customers Hours of Interruption due to Failed Equipment.

These measures were developed by reviewing reliability trends, while also benchmarking against similar utilities as intended by the Ontario Energy Board. SAIDI performance for Alectra Utilities has been in the third quartile in comparison to other Ontario Local Distribution Companies. The contribution to SAIDI from customer hours of interruption due to Failed Equipment has been in the fourth quartile, and is the single greatest contributor to unreliable service.

Section G.1 and *Section G.2* below provide additional details for the System Reliability performance measures being proposed:

- G.1) System Average Interruption Duration Index (SAIDI) Excluding Major Event Days
- G.2) Customer Hours of Interruption due to Failed Equipment

The following sections explain the purpose and manner of calculation for each measure.

G.1 SAIDI Excluding Major Event Days

SAIDI (System Average Interruption Duration Index) is a measure in hours of the total duration of interruptions for the average customer served in a given year. SAIDI represents the quotient obtained by dividing the total customer hours of interruption for sustained outages greater than or equal to one minute by the number of customers served.

Equation 5.2.3 - 1 System Average Interruption Duration Index

$$\text{SAIDI}=\frac{\sum \text{Customer Hours of Interruption}}{\text{Total Number of Customers Served}}$$

Major Event Day (MED) and Loss of Supply (LOS) are two separate events used to distinguish and clarify reliability performance for a utility.

A Major Event Day (MED) is a day in which the daily SAIDI exceeds a MED threshold value (TMED). In calculating the daily SAIDI, interruption durations that extend into subsequent days accrue to the day on which the interruption originates. Alectra Utilities applies the 2.5 Beta method to identify MEDs as per the Institute of Electrical and Electronic Engineers (IEEE) Standard 1366. Alectra Utilities' application of the IEEE Standard 1366 for MED monitoring meets the OEB's Electricity Reporting and Record Keeping Requirements (RRR) dated November 2018. Alectra Utilities utilizes the MED Threshold value to identify events that are significantly beyond its typical system performance indicators. The company further examines such major events to understand the contributing factors, distribution system vulnerabilities, as well as system maintenance and sustainment needs, to mitigate the impacts of such events in the future. Details for all MEDs can be found in *Appendix M - Major Event Days (2019 – 2024).*

A Loss of Supply (LOS) event is defined by the OEB in the RRR is an interruption due to problems associated with the distributions system owned and/or operated by another distributor, and/or in the transmission system. Including interruptions caused by the transmitter or host distributor scheduled interruptions.

Alectra Utilities views MEDs as issues which require investment over multiple DSPs do to the significant investment required. While outages caused by LOS are beyond the Distributor's control, however, Alectra Utilities works closely with the transmitter to reduce the risk of these events as they negatively impact its customers. Solutions such as Distribution Automation or feeder capacity investments, which ensures quicker restoration of power to customers from alternate sources. Although Alectra Utilities has set practices and plans to mitigate the impacts of LOS outages over the DSP planning period, there are specific force majeure or catastrophic outage events to which Alectra Utilities cannot reasonably and prudently mitigate. In summary Alectra Utilities continues to support the inclusion of LOS in its performance metrics for reliability as provided in *EB-2019-0018 Exhibit 4, Tab 1, Schedule 1, page 106*, Inclusion of Loss of Supply Outages in System Reliability Performance Measurement.

Alectra Utilities selected a 5-year period, 2020-2024 SAIDI, excluding MEDs but including LOS to set its target. A five-year sample size was used over a ten-year range due to the improving reliability over the last few years. As discussed above MEDs were not included, however LOS is included in the SAIDI metric.

Based on the investments proposed within this DSP over the 2027-2031 period, Alectra Utilities expects to see a 20% improvement in SAIDI by 2031 against the historical 5-year performance as provided in Table 5.2.3 - 8.

Table 5.2.3 - 8 System Reliability (SAIDI – Excluding MEDs) Custom Performance Measure

Measure Category	2027-2031 Performance Measure	Avg. of the last 5 years (2020-2024)	Target (End of 2031)
Operational	SAIDI – Excluding MEDs	0.92 hours	0.74 hours

G.2 Failed Equipment

As detailed in Figure 5.2.3 - 1 and Figure 5.2.3 - 2 below, Equipment Failure is the top contributor to reliability at Alectra Utilities, responsible for 44% of unplanned outages and 50% of customer hours of interruption. To measure the impact of its investments on reliability performance due to Failed Equipment, Alectra Utilities proposes a metric centred on the duration of these outages.

Similar to the SAIDI metric noted above a five-year historical period was used as the based to set the target. Based on the investments proposed over the 2027-2031 period Alectra Utilities expects there should be a 20% improvement in the duration of outages by the end of 2031, as illustrated in Table 5.2.3 - 9.

Table 5.2.3 - 9 System Reliability (Failed Equipment) Custom Performance Measure

Measure Category	2027-2031 Performance Measure	Avg. of the last 5 years (2020-2024)	Target (End of 2031)
Operational	Failed Equipment - CHI	443,101	354,481

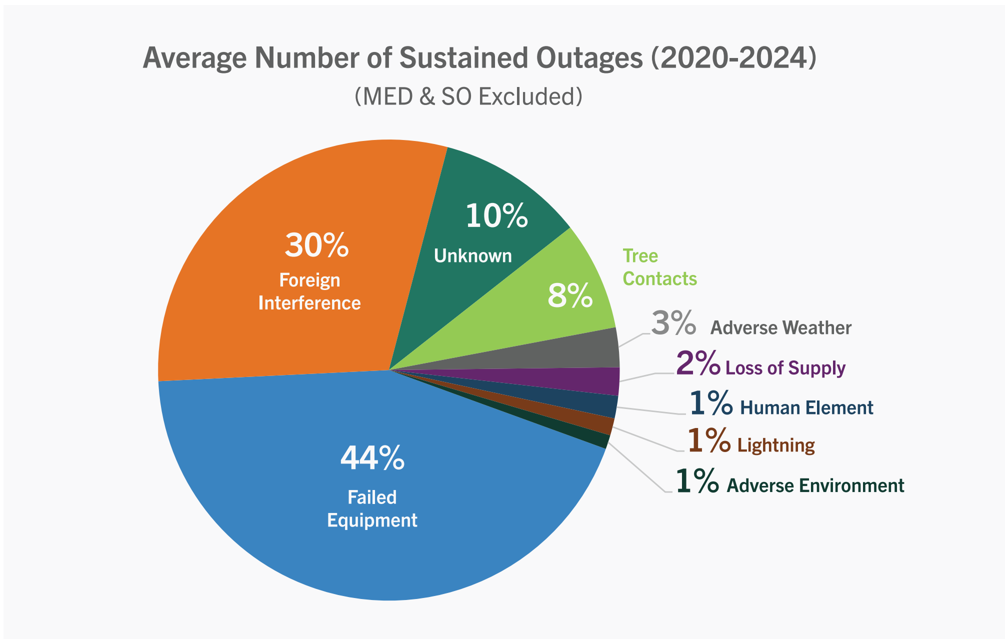

Figure 5.2.3 - 1 5-Year (2020-2024) Average Number of Sustained Events (Scheduled Outages Excluded) by Cause Code

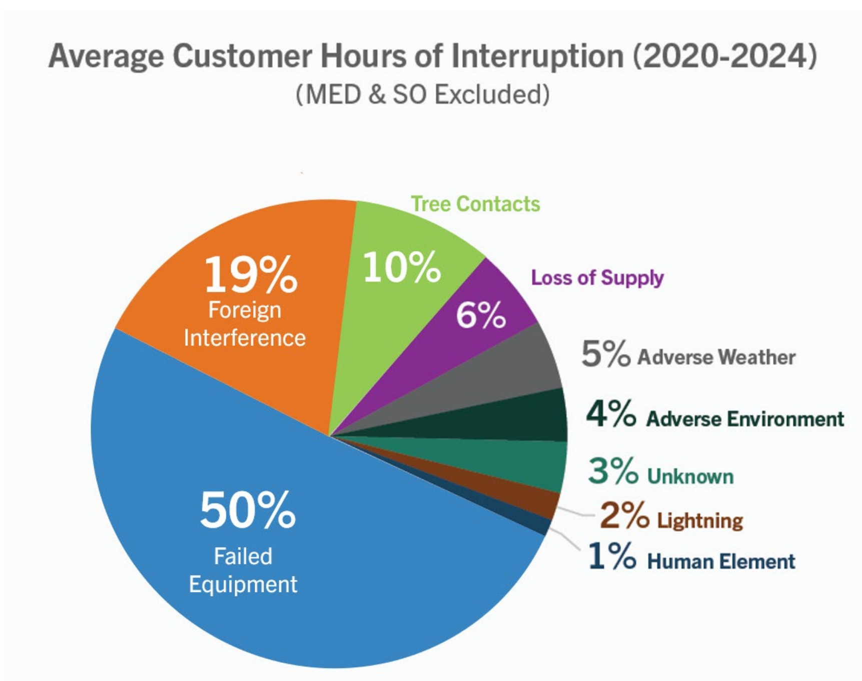

Figure 5.2.3 - 2 5-Year (2020-2024) Average Customer Hours of Interruption (Scheduled Outages Excluded) by Cause Code

5.3 Asset Management Process

5.3.1 Asset Management Process Overview

5.3.1.1 Asset Management Process

Alectra Utilities utilized an established Asset Management Process to develop the Capital Investment Plan (CIP), which forms the basis of the 2027-2031 Distribution System Plan (DSP). Alectra Utilities' DSP is designed to provide value for rate payer money and to appropriately balance the needs and preferences of its customers, its distribution system requirements, and relevant public policy objectives.

The Asset Management Process consists of four stages:

1. Identification of Investment Needs
2. Capital Investment Planning & Optimization
3. Work Execution
4. Continuous Improvement

Alectra Utilities optimized the investments to form the CIP using IFS Copperleaf Portfolio (Copperleaf) software. Copperleaf is an industry-leading Asset Investment Planning & Management (AIPM) software that applies multivariable optimization capability to maximize the value of an investment portfolio. The software evaluates diverse business cases uniformly in a consistent and objective manner using Alectra Utilities' Value Framework.

Alectra Utilities has continued to make improvements to its Asset Management Process. Since 2020, key enhancements include the improvement of business case development through the implementation of comprehensive user workshops and training modules, and updated Value Framework benefits and risk measures to align with emerging policy objectives such as cybersecurity and environmental stewardship. Alectra Utilities has also integrated an Advanced Asset Analytics platform and incorporated Predictive Analytics (PA) into its asset renewal planning practice. These fundamentals strengthened the Asset Management Process to improve the identification and assessment of needs, capture of investment benefits and risks, thereby supporting the development of an optimized CIP. Alectra Utilities' Asset Management Process ensures that the optimized investments are responsive to customer needs and preferences, address required distribution system and operational needs, align with public policy, and meet regulatory compliance requirements.

The first stage of Alectra Utilities' Asset Management Process is the identification of investment needs and developing business cases based on consideration of customer needs, priorities and preferences derived from the first phase of customer engagements as well as identification of needs from internal and external drivers. The second stage of the process involves capital investment planning and optimization, utilizing Copperleaf and Alectra Utilities' Value Framework to evaluate each investment using value measures across a wide range of dissimilar investment business cases. Once the CIP is optimized and a draft plan is developed, Alectra Utilities returns to customers with a cost drafted plan with investment choices to collect customer feedback as part of the second phase of customer engagement. After collecting customer feedback on the draft plan, the utility incorporates customer preferences, adjusts and finalizes the CIP. Once the CIP is finalized, Alectra Utilities prepares the CIP for inclusion into the multi-year Financial Plan for leadership and Alectra Utilities' Board of Directors approval.

The next stage of Alectra Utilities' Asset Management Process involves the execution of the capital work as per the CIP in the approved Financial Plan. The CIP is provided to the Design Group and Program Delivery Group (PDG) to design, plan and schedule the execution of work. This stage includes the detailed project scheduling, planning, and monitoring of work completion as per the CIP. The fourth and final stage of Alectra Utilities' Asset Management Process includes continuous improvement by reviewing work and project deliverables, reporting on performance measures, and developing improvement action plans that inform the next cycle of the Asset Management Process. The Alectra Utilities' Asset Management Process is illustrated in Figure 5.3.1 - 1.

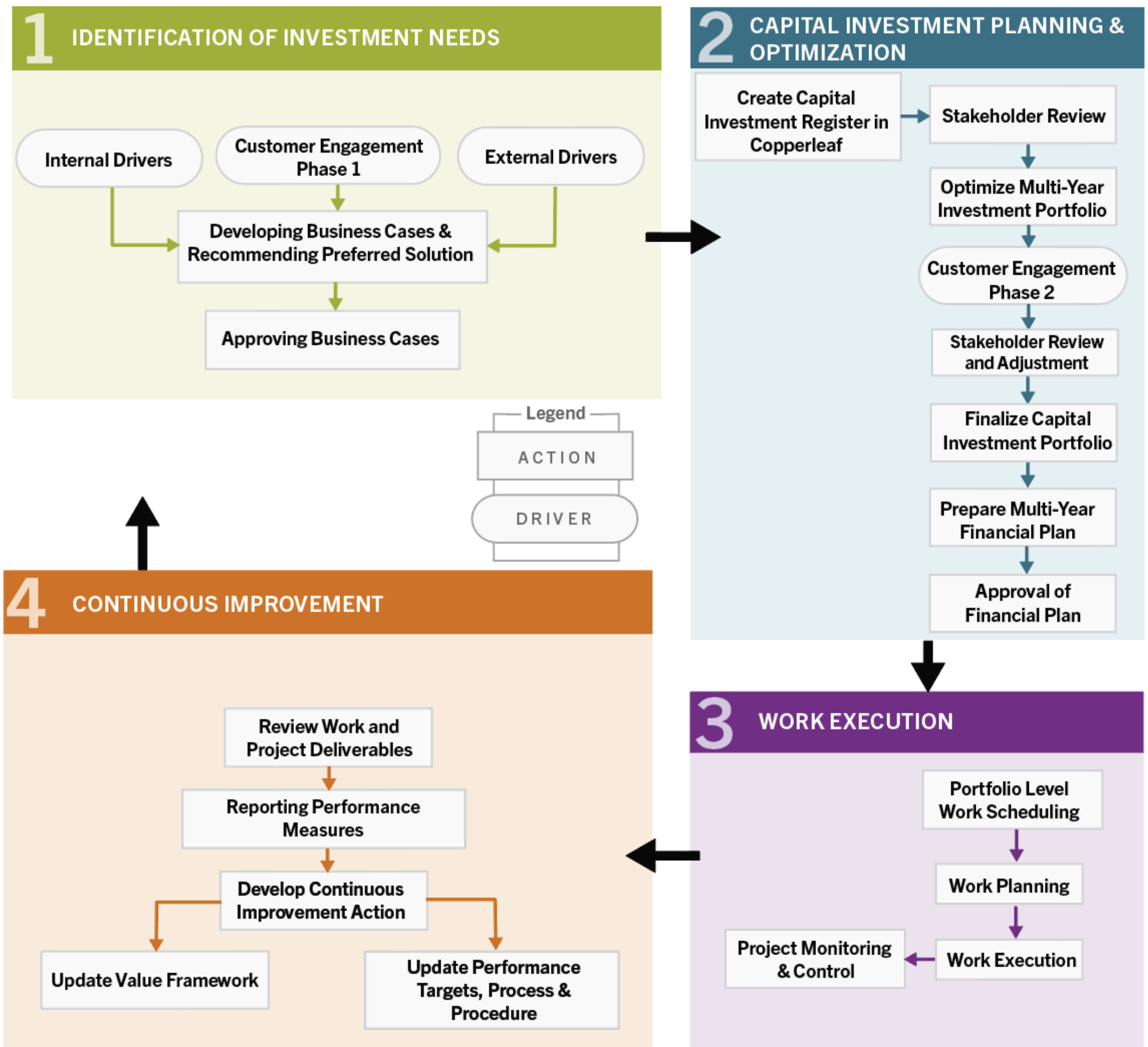

Figure 5.3.1 - 1 Asset Management Process

A Stage 1 - Identification of Investment Needs

The first stage of the Alectra Utilities' Asset Management Process involves gathering and understanding customer needs, preferences and priorities of customers, assessing distribution system requirements, as well as incorporating public policy objectives and obligations. Alectra Utilities Subject Matter Experts (SME) consider customer needs and preferences, internal and external drivers to identify investment needs and develop corresponding business cases with recommended solutions. Figure 5.3.1 - 2 illustrates the drivers and action steps Alectra Utilities completes in the first stage of the Asset Management process. The output of the first stage is a list of reviewed and approved investment business cases which serve as the input into the second stage of the process.

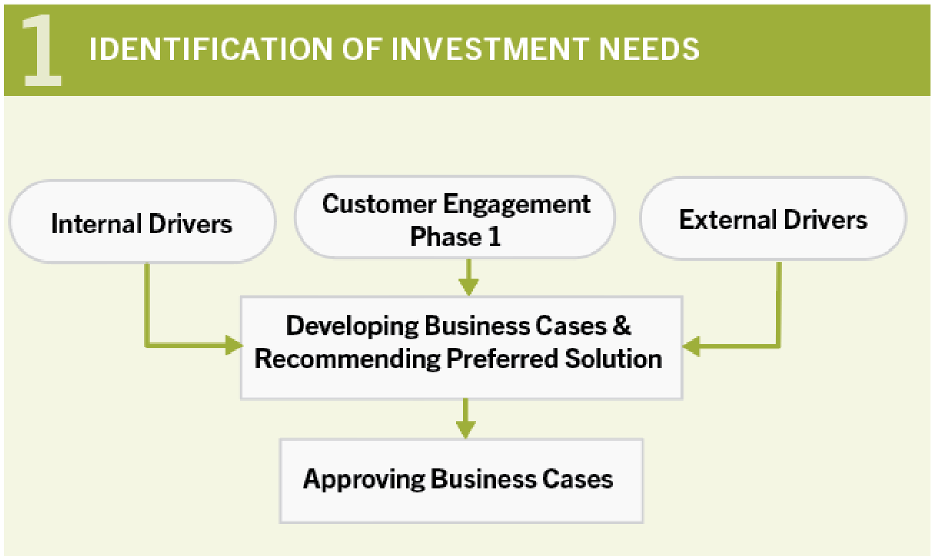

Figure 5.3.1 - 2 Identification of Investment Needs Procedure

A.1 Customer Preferences (Customer Engagement – Phase 1)

Customer engagement is the first step in Alectra Utilities' Asset Management Process. Alectra Utilities first engages with its customers to gather and understand their needs, priorities, and preferences, and to assess which investments will achieve outcomes aligned.

Building on customer expectations developed from ongoing customer interactions (refer to *Exhibit 1, Tab 5, Schedule 1 Ongoing Customer Engagement)*, Alectra Utilities enlisted Innovative Research Group ("Innovative Research") to facilitate customer engagement to inform the development of the 2027-2031 DSP.

Alectra Utilities initially drafted five objectives for capital investment needs for 2027-2031:

1. Maintain reliable, safe and dependable assets and infrastructure
2. Prepare the grid for anticipated growth and electrification
3. Empower customer choice and enhance customer experience
4. Optimize the grid with automation, digitization and analytics
5. Improve grid resilience and adapt to extreme weather

Innovative Research conducted the first phase of customer engagement to obtain customer needs and priorities based on the drafted objectives in the first quarter of 2024 and in the second quarter of 2024, Innovative Research delivered its findings (in the form of a summary "placemat"[42]). Alectra Utilities customers expressed that reliable service and reasonable prices were the top priorities for residential, GS<50kW, and GS>50kW customers. Meanwhile, Large Use customers emphasized the importance of improving both system reliability and customer experience (refer to *Exhibit 1, Tab 5, Schedule 2 Application-Specific Customer Engagement* for a detailed explanation of the outcomes from the consultation). Based on the results of the first phase of customer engagement, Alectra Utilities incorporated the findings into the planning process, updated the drafted objectives and developed the following DSP themes:

1. **Renewing and Replacing Deteriorated Infrastructure:** Ensuring reliable, safe and dependable assets and infrastructure
2. **Meeting Growing Electricity Demand:** Prudently preparing the grid for anticipated growth and electrification
3. **Enabling Resiliency and Modernization:** Increase system uptime and performance against adverse weather, and communicate effectively with customers

Alectra Utilities' Asset Management Process was directly informed by customer input, emphasizing the importance of maintaining reliability while ensuring cost effectiveness. Alectra Utilities then proceeded with the development of business cases with recommended investment

[42] The placemat is attached in the *Exhibit 1, Tab 5, Schedule 2 Application-Specific Customer Engagement*.

solutions that considered various pacing options and investment levels in response to customers' needs.

A.2 External Drivers

Alectra Utilities defines external drivers as obligations to customers, the public, and external stakeholders. As outlined in Table 5.3.1 - 1, external drivers necessitate mandatory investments for Alectra Utilities to ensure fulfillment of customer service commitments, compliance with regulatory and legal requirements, support for externally driven projects, alignment with regional planning initiatives, and upholding environmental stewardship and public safety.

Table 5.3.1 - 1 External Drivers

External Source	Investment Need Driver Description
Customer Connections	• Obligation to accommodate requests for connections of residential, industrial or commercial customers.
Regulatory	• Compliance with regulatory requirements, including applicable codes, license conditions, standards, and Electrical Safety Authority (ESA) requirements. • Public policy responsiveness.
Municipal, Regional and Provincial Agencies	• Relocation of facilities due to Municipal, Regional and Provincial Government project requirements relating to street lighting, road widening, new subdivisions, water main construction, etc.
Environmental	• Compliance with environmental obligations pursuant to applicable legislation, regulations, standards and other requirements of public and government agencies.
Regional Planning – Integrated Regional Resource Plan (IRRP) and Regional Infrastructure Plans (RIP)	• Investment drivers derived from the outcomes of regional planning activities.

Alectra Utilities' Asset Management Process takes account of investment needs driven by wide range of external factors, including alignment with regulatory mandates such as the OEB's RRF. The RRF identifies four key utility outcomes: customer focus, operational effectiveness, public policy responsiveness, and financial performance. Alectra Utilities integrates these regulatory principles into its decision-making to ensure that all capital expenditures align with these outcomes. Alectra Utilities has also ensured responsiveness to policies and directives from the

Minister of Energy, such as those provided to the OEB on June 12, 2025, to ensure that Alectra Utilities' Asset Management Process is responsive to Ontario's broader public policy objectives, including *The Get It Done Act*[43]*, and The More Homes Built Faster Act*[44], which set infrastructure investment and system planning direction.

Alectra Utilities performed climate risk and vulnerability assessments to support the development of the DSP. To support this assessment, Alectra Utilities engaged a third-party, Hatch Ltd., to conduct a comprehensive vulnerability study, the "Climate Risk and Vulnerability Assessment of the Alectra Utilities' Distribution System" (refer to *Appendix G - Climate Risk & Vulnerability Assessment*). The study modelled the impact of evolving weather patterns within Alectra Utilities service area to identify vulnerable areas prone to climate perils (refer to *Chapter 5.3.2 (Section 5.3.2.1 C)*). The outcome of the climate study informed Alectra Utilities' third objective of this DSP, Enabling Resiliency and Modernization by identifying vulnerable areas of the distribution system to adverse weather events.

A.3 Internal Drivers

Alectra Utilities considers internal investment drivers when assessing distribution system and general plant requirements and needs. Internal drivers of investments include system performance issues and risks, asset condition, system capacity requirements to safely and effectively operate the distribution system as well as employee and public safety requirements. Internal drivers of investments are outlined in Table 5.3.1 - 2.

[43] https://www.ola.org/en/legislative-business/bills/parliament-43/session-1/bill-162
[44] https://www.ola.org/en/legislative-business/bills/parliament-43/session-1/bill-23

1 **Table 5.3.1 - 2 Internal Drivers**

Internal Drivers	Driver Description
Asset Performance (Reliability)	• Trends and issues concerning reliability performance indices and metrics. • Worst-performing feeders and associated remedial needs.
Performance Measures (i.e. Key Performance Indicators) / Service Quality	• Performance Measures and Service Quality targets (refer to *Chapter 5.2.3 Performance Measurement for Continuous Improvement*)
Risk Management	• Investments to mitigate identified and unacceptable levels of risks related to system capacity adequacy, safety, environmental, financial, reputational, internal policies and procedures, and information technology capacity. *Refer to Appendix C - Alectra Value Framework Definition Document*
Condition Assessments	• Identifying hot spots in the grid based on asset analytics data • Distribution asset health as determined from asset data registers and inspections. Data utilized with other data sets using Alectra Utilities' Asset Analytics Platform. • Station asset health as determined from inspection and testing. • Fleet condition based on deterioration, repair history, service reports, mileage, engine hours, etc. • Building and property condition. *Refer to Chapter 5.3.2 Overview of Assets Managed*
Predictive Analytics	• Projecting asset replacements and pacing investments related to programs for poles, switchgears, transformers, switches and fleet. *Refer to Chapter 5.3.3 Asset Lifecycle Optimization Policies and Practices*
System Capacity	• Need for transformation and distribution capacity expansions based on short, medium and long-term distribution system planning requirements. • System planning requirements relating to annual peak loading. *Refer to Appendix J – Load Forecast & System Adequacy Assessment Report*
Employee and Public Safety	• Capital investments arising from the ongoing review, development and updating of safety-related policies and procedures. • Required infrastructure/equipment to eliminate unsafe conditions. • Initiatives in response to specific safety-related issues or industry innovations.
Climate Risks & Vulnerability	• Assessing the impact of climate-related risks on infrastructure resilience and integrating adaptive strategies to ensure system reliability, operations and maintenance. • Refer to *Chapter 5.3.2 (Section 5.3.2.1 C)*

A.3.1 Asset Capacity/Utilization Assessment

This section outlines Alectra Utilities methodology of assessing asset capacity and distribution system capacity as an internal driver for investment. Alectra Utilities employs 10 criteria for planning the distribution system and determining the capacity thresholds that trigger system expansion investments, as discussed below:

1. Alectra Utilities applies a deterministic N-1 network planning approach. Under this approach, Alectra Utilities ensures a continuous supply for connected loads when a single major network station element is out of service until that station element is repaired or replaced (hence, "N-minus-1"). This planning approach requires Alectra Utilities to construct sufficient capacity redundancy into the distribution network to withstand a single network station element outage without interrupting service to customers.
2. Alectra Utilities constructs and operates an "open looped" network design, which requires multiple feeders to be interconnected via normally-open points. The utility can close these points to create a circuit and re-route the flow of electricity to customers to maintain service when an element of the network (e.g. a station transformer) fails or is otherwise taken out of service. Where technically and economically feasible, Alectra Utilities will connect loads of 500kVA or greater with a looped supply connection.
3. Alectra Utilities plans to interconnect legacy utility systems where feasible (i.e. create tie points between legacy utility distribution systems) to increase system utilization, improve reliability, improve resiliency, and provide back-up capability.
4. Alectra Utilities operates primary feeders (44/27.6/13.8/8.32/4.16kV) under normal conditions (system peak) to a maximum loading that is the lesser of 2/3rd egress cable rating or 2/3rd of the 600-amp contingency rating.
5. Alectra Utilities operates primary feeders under contingency conditions to a maximum loading rating of the lesser of the egress cable or 600-amp.
6. Alectra Utilities plans to implement triad configuration for substations when applicable (i.e. three substations interconnected through their secondary feeders, or two transformers at a single substation site if interconnection to adjacent substations is not feasible).

7. Where a transmission system-connected transformer station is required, Alectra Utilities plans to continue building Dual Element Spot Network transformer stations.
8. Alectra Utilities utilizes a 10-day Limited Time Rating (10-Day LTR) for transformer station capacity planning criteria.
9. A transformer that exceeds its Oil Natural Air Natural (ONAN) rating (an indication that the transformer is over the base rating) will trigger a review of substation loading, including analysis of load transfers to adjacent substations, the loading impact of anticipated growth, land availability, resource availability, and other contingencies. Capacity augmentation will only be considered when a transformer will exceed its respective maximum top-stage rating; ONAN for transformers with no fans, ONAF for transformers with single-stage fans, or ONAF/ONAF for transformers with dual-stage fans.
10. Alectra Utilities will maintain a spare transformer to mitigate the risk of a prolonged station transformer service interruption.

A.3.2 Capacity Planning and Assessment

This section outlines Alectra Utilities methodology of capacity planning and assessment. Alectra Utilities regularly monitors and assesses short-term and long-term system capacity, primarily through its annual peak demand load forecasting process and system adequacy assessment studies. The capacity planning and assessment process also includes Alectra Utilities' ongoing coordination and participation in regional planning activities, as well as DER/generation connection assessments, in collaboration with Hydro One Networks Inc. (HONI) and the Independent Electricity System Operator (IESO) (refer to *Appendix J – Load Forecast & System Capacity Adequacy Assessment Report* for a detailed outline of system adequacy assessment and *Chapter 5.2.2 Coordination with Third Parties* for a summary of completed and ongoing regional planning activities).

A.3.2.1 Load Forecast

Alectra Utilities produces an annual system peak demand load forecast that reflects both medium-term and long-term demand projection. The peak demand load forecast process, illustrated in Figure 5.3.1 - 3, provides important insights into where and when additional system capacity will be required, including the need to account for contingency scenarios for grid flexibility to restore demand from unplanned outages including emergency restoration from storms and loss of supply events.

Alectra Utilities is currently a summer peaking utility. Alectra Utilities' peak demand load forecast is representative of normalized weather conditions (hot weather scenario is assumed once every 10 years[45], and normal weather is assumed once every 2 years[46]), historical load patterns, and expected service growth informed by long-term customer, municipal regional and provincial plans. The peak demand load forecast methodology also considers other relevant factors, such as the expected impact of Distributed Generation (DG), Distributed Energy Resources (DERs), Global Adjustment (GA) Impact, and Conservation and Demand Management (CDM).

[45] 1-in-10 refers to a hot weather scenario, which has the probability of occurring 1 in 10 years. The system is planned to meet 1 in 10 weather conditions.
[46] 1-in-2 refers to a normal weather scenario, which has 50% probability of happening each year.

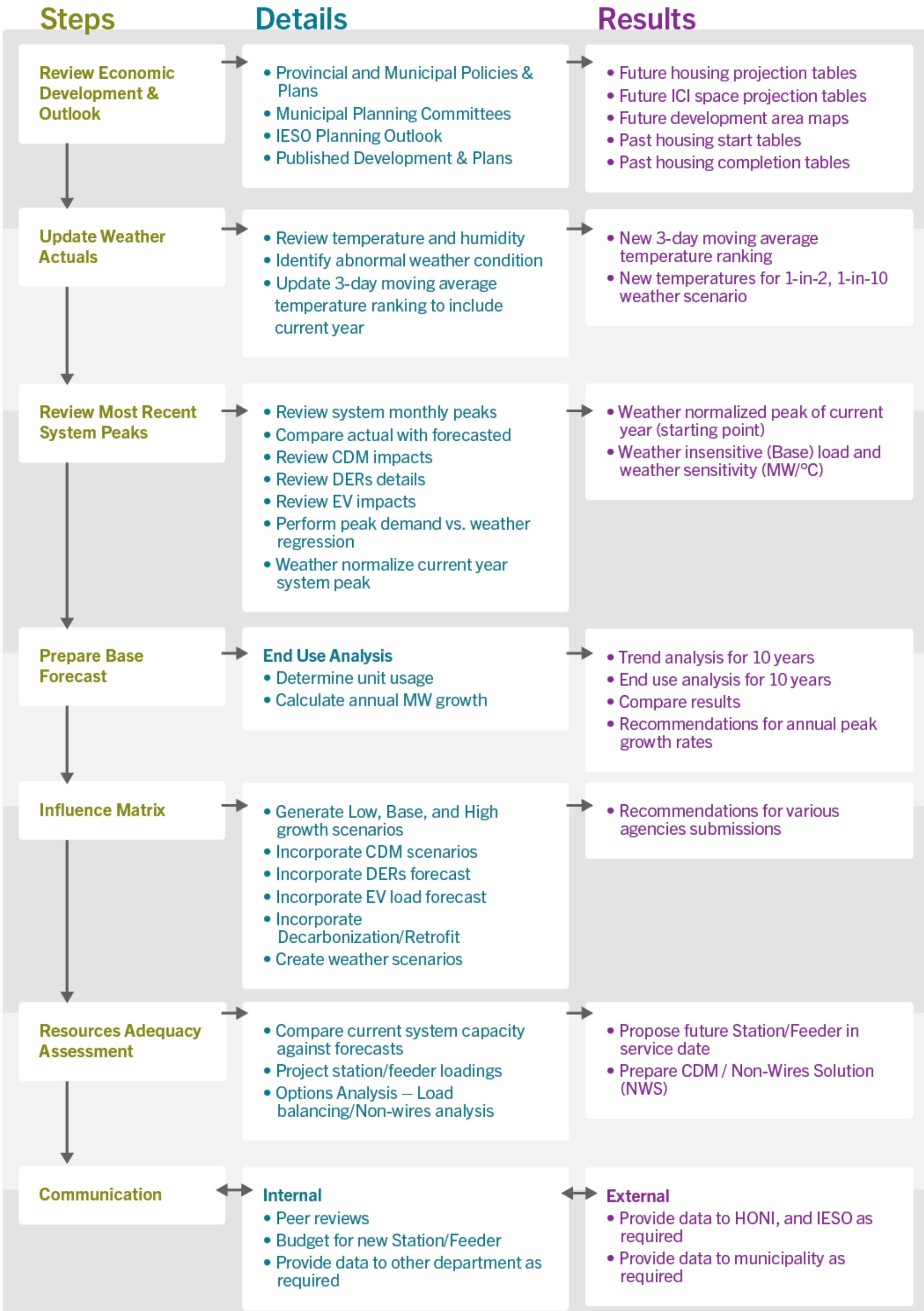

Figure 5.3.1 - 3 Load Forecast Process

Alectra Utilities has developed its system peak demand load forecast utilizing an end-use analysis methodology. This methodology incorporates historical system data, economic growth indicators (population, housing, employment) for each of the six Alectra planning zones (York, Simcoe, Central North - Brampton, Central South - Mississauga, West and Southwest) and identified emerging demand drivers (e.g. Artificial Intelligence - Data Centre expansion, transportation electrification). The end-use forecast methodology produces an accurate and transparent forecast that reflects both historic load growth and new trends impacting the distribution system capacity. Alectra Utilities system peak load forecast was developed and implemented consistent with OEB's Load Forecast Guideline[47].

Applying the end-use methodology, Alectra Utilities' non-coincident peak demand is projected to increase by 1,469MW from 5,938MW in 2024 to 7,407MW by 2031, representing an average annual growth rate of approximately 3.2%. This increase is driven by several key factors, which are summarized in Table 5.3.1 - 3.

Table 5.3.1 - 3 Forecasted System Adequacy Assessment Load Growth by Driver (2025-2031)

Growth Driver	Current Load (MW) 2024	Forecast Load (MW) 2031	Forecast CAGR Growth 2025-2031	Load Growth Contribution (%) 2025-2031	Load Growth Contribution (MW) 2025-2031
Population, Housing and Employment Growth	5761	6281	1.24%	35%	520
Data Centers (Artificial Intelligence, Storage, Cloud Computing)	115	540	24.7%	29%	425
Transportation & Electrification	61	586	38.2%	36%	524
Total				**100%**	**1,469**

Hatch Ltd. (Hatch) was retained to conduct an independent review of Alectra Utilities' peak demand load forecast methodology, inputs and resulting 2024-2034 peak load forecast. In addition, Hatch reviewed the energy forecast model to ensure that the overarching assumptions

[47] Load Forecast Guideline for Ontario, October 13, 2022

for both forecasts were consistent. Hatch's report is provided in *Appendix K – Load Forecast Review Report*.

Hatch reviewed Alectra Utilities' load forecast methodology, including the input data and sources, as well as the system peak demand forecast models. The review included the baseload forecast, growth in demand driven by new residential as well as industrial, commercial and institutional (ICI) growth, weather correction, reductions resulting from the conservation and demand management initiatives, peak load growth driven by EV uptake and sensitivity scenario analysis for the decarbonization of heating. Upon completing the peak demand forecast assessment, Hatch determined that Alectra Utilities used a best practice approach in preparing the system peak demand load forecast.

Furthermore, Hatch confirmed that Alectra Utilities used accepted approaches to load forecasting in alignment with OEB's Load Forecast Guidelines for Ontario.[47] Hatch concluded that Alectra Utilities incorporated a wide range of reputable data sources and inputs in preparation of the system peak load demand forecast. Hatch observed that Alectra Utilities collected and used the most recent available plans for all major municipalities that it serves to develop the peak load forecast.

Hatch also determined that the methodology and assumptions used to develop the system's peak demand load forecast are well-aligned with those used in the preparation of the energy forecast, which is used to model future revenue.

A.3.2.2 System Adequacy Assessment

After completing the system peak demand load forecast, Alectra Utilities completes a system capacity adequacy assessment for its stations and feeders to ensure each can meet the projected load growth and appropriate contingencies. In alignment with applicable planning criteria, Alectra Utilities System adequacy assessment takes into account available capacity and future capacity requirements in order to arrive at identified needs and measures for capacity expansion through either traditional or non-wires alternatives.

A.3.2.3 Capacity Risk Mitigation

Alectra Utilities mitigates capacity-related risk utilizing a wide range of approaches including system reconfiguration and load transfers, equipment enhancements, non-wires solutions, and station or feeder expansion projects as summarized below.

- **System Reconfiguration and Load Transfers**: Where feasible and economical based on Alectra Utilities' analysis, system reconfiguration and load transfers are undertaken as effective means of addressing the capacity shortfalls.
- **Asset Capacity Upgrade**: Alternative to system reconfiguration or load transfers, Alectra Utilities considers increasing the rating of equipment, either at the stations (e.g. by upgrading transformers with additional cooling) or, on the lines (e.g. by conductor upgrade to increase ampacity).
- **NWA or Wires Expansion**: If distributed energy resources (DER) or demand response (DR) is available (or feasible to provision), Alectra Utilities leverages non-wires solutions. Alectra Utilities can potentially address localized demand through non-wire options. When NWA cannot meet the need, wire expansion options such as station expansions are considered. These are typically coordinated with any planned renewal activities at the same site. Where a transformer station requires greater capacity, Alectra Utilities coordinates with HONI and the IESO at a regional planning level. Where HONI owns and operates the relevant station, Alectra Utilities may be required to make a capital contribution for any expansion or enhancement.

Additional details of stations and feeder expansion projects are found in *Appendix B12 - Lines Capacity* and *Appendix B13 - Station Capacity*.

A.3.2.4 DER Connections

Alectra Utilities plans, designs and constructs its distribution system to safely and reliably serve customers with effective monitoring and protection. However, Alectra Utilities distribution system was not initially constructed with the capability to connect and manage a large number of Distributed Energy Resources (DERs). Accordingly, the amount of generation and energy resource capacity that can be connected to the distribution system is constrained by a variety of physical factors, such as supply feeder ampacity, power quality, equipment ratings, limits on reverse power flow, and short circuit capacity at the transformer stations and substations.

Alectra Utilities assessed its transformer stations as well as HONI-owned stations for the capability of connecting DERs; for a detailed listing the stations and connection capacities, refer to *Appendix A - System Capability Assessment for Renewable Energy Generation*.

A.3.2.5 Assessment of System Reliability Performance

Refer to *Chapter 5.2.3 (Section 5.2.3.2 G)* for a detailed explanation on the process Alectra Utilities uses to assess system reliability performance.

A.4 Business Cases Development

Alectra Utilities initiated the multi-year capital investment planning process that forms the CIP in January 2024 by gathering stakeholder working groups composed of internal Subject Matter Experts (SMEs) and stakeholders.

Alectra Utilities ensured SMEs developed comprehensive business cases that are consistent and aligned with Alectra Utilities Value Framework through training sessions focused on developing business cases and leveraging Copperleaf to document and register each business case. Business cases developed using a consistent approach with alignment to the Value Framework enables Alectra Utilities to compare each business cases across the entire portfolio of business cases. Each business case includes a description of the need or problem, urgency, and if applicable, project dependencies. Business cases also include one or more potential alternatives, each with its own proposed start date, in-service date, budget forecast, incremental benefits and risk mitigation, which is then scored on criteria of Alectra Utilities Value Framework. For fleet and certain System Renewal projects such as poles, switches, switchgears, transformers, project owners leverage the Predictive Analytics tool within Copperleaf Asset to establish renewal pacing options for each asset type (refer to *Section 5.3.1.3 A* for description of Alectra Utilities Predictive Analytics tool).

A.5 Business Cases Approval and inclusion into Capital Investment Register

Alectra Utilities ensures that its CIP aligns with its strategic objectives and customer needs through independent reviews and an approval process of each business case. Alectra Utilities leverages Copperleaf's system workflow function to facilitate the business case review and approval process. To ensure consistency in review and approval, business case reviewers and approvers receive training on the Value Framework. Business case approvers ensure that each investment business case was accurately developed and documented before approval and included in the investment register. Business Case reviews include consideration of the investment need, the solution to address the need, alternative solutions considered, the rationale for the preferred solution, and the Value Measures (within the Value Framework) that were used to determine the overall value of the project. Alectra Utilities only considers approved business cases for inclusion in the registry for optimization, but only business cases that were optimized into the portfolio are included in the Capital Investment Plan.

B Stage 2 - Capital Investment Planning and Optimization

Alectra Utilities applies a harmonized, uniform and systematic Capital Investment Planning and Optimization through which the company collects, assesses, evaluates, and optimizes system and operational investment solutions for distribution system and general plant initiative. Once Alectra Utilities develops an optimized CIP, Alectra Utilities returns to customers for the second phase of customer engagement to collect customer feedback on investment choices. Alectra Utilities then incorporates customer feedback to finalize the CIP and prepare the multi-year financial plan for approval. The process takes into consideration customer input on options from the optimized portfolio of investments and the respective trade-offs. This stage of the process is shown in Figure 5.3.1 - 4.

Figure 5.3.1 - 4 Capital Expenditure and Investment Portfolio Optimization

At the start of the second stage of the Asset Management Process, Alectra Utilities creates a capital investment register based on approved business cases from the first stage of the Asset Management Process. Business Cases included in the register are subjected to another round of stakeholder reviews before the portfolio optimization. This additional stakeholder review further ensures a standardized and consistent methodology for analyzing and validating Alectra Utilities' diverse capital investment needs and proposed solutions. This section provides a comprehensive overview of the process that Alectra Utilities has used to develop its multi-year Capital Investment Plan that underpins the DSP, organized as follows:

- Capital Investment Optimization
- Customer Preferences (Customer engagement – Phase 2)

B.1 Capital Investment Optimization

The Copperleaf AIPM software utilizes a proprietary Mixed Integer Linear Programming (MILP) algorithm to optimize capital investments within constraints including expenditure, resources, timing and if applicable, project dependencies. In summary, the optimization algorithm optimizes investments among available alternatives and dynamically calculates a portfolio that maximizes value, considering the impact of deferral or investment acceleration within applied constraints. The output of the optimization process is a multi-year actionable capital investment plan. The key elements of the process are described in greater detail in the sections below.

B.1.1 Create Capital Investment Register

Once a business case is reviewed and approved through the Copperleaf approval workflow process, the Copperleaf software incorporates the business case into the Copperleaf Capital Investment Register in preparation for the portfolio optimization process. As part of the multi-year planning process that Alectra Utilities used to develop the Capital Investment Plan for this DSP, the company developed business cases representing over $5B in investment needs. These cases were in the Capital Investment Register for consideration through the optimization process.

B.1.2 Optimize Multi-Year Investment Portfolio

Alectra Utilities' management conducted a review of the investments submitted and approved in the multi-year Capital Investment Register and guided the approach to optimizing the portfolio of projects. During this stakeholder review, the management team discussed the level of projects submitted in each investment category and the approach of grouping projects within Copperleaf optimization Planning Groups.

The objective of the optimization process was the development of a portfolio of capital investments that provides maximum value while respecting optimization constraints, including risk tolerances and timing requirements. Optimization is an iterative process involving reviews of optimization outputs by management, as well as the stakeholder working groups and business case owners.

B.1.2.1 Copperleaf Value Framework

The Copperleaf software tool utilizes Alectra Utilities Value Framework as a common economic scale to evaluate multiple investments against each other, allowing for uniform, consistent, and objective comparisons of business areas. Alectra Utilities Value Framework consists of 23 unique value measures that include cost, benefits and risks. Value Measures are normalized to a common scale, where one value point is equal to $1,000. For each business case, Copperleaf aggregates the financial measures, benefit measures, and risk measures using a net present value methodology to calculate an investment value score.

Alectra Utilities Value Framework considers each proposed capital investment business case based on its own merits. When developing a business case within the Copperleaf software, SMEs are guided through a detailed questionnaire to input the cost, benefit and risk measures, which include probability and impact relative to time.

The Value Framework is aligned with the OEB's Distribution System Code (DSC), OEB's RRF outcomes, and Alectra Utilities' strategic objectives that balance values and risks, enabling a quantitative and consistent approach to optimize investments. Table 5.3.1 - 4 provides an overview of the Value Models Categories and individual Value Models that comprise the Value Framework.

Table 5.3.1 - 4 Alectra Utilities' Value Framework

Value Category	OEB's RRF Outcomes	Value Measure
Financial	Financial Performance Operational Effectiveness	Capital Financial Benefit
		OM&A Financial Benefit
		Future Revenue Model
		Financial Risk
Reliability	Customer Focus Operational Effectiveness	Distribution System Capacity Risk
		Reliability Benefit
		Reliability for Spares Benefit
Safety & Security	Customer Focus Public Policy Responsiveness	Cyber Security Benefit
		Cyber Security Risk
		Safety Risk
Regulatory & Compliance	Public Policy Responsiveness Financial Performance	Compliance Risk
		Application Ready Organization Benefit
Customer Service	Customer Focus Operational Effectiveness	Customer Communication Benefit
		Customer Centricity Benefit
		Customer Service Benefit
Environmental	Customer Focus Public Policy Responsiveness	Environmental Improvements Benefit
		Environmental Risk
Public & Employee Perception	Customer Focus Public Policy Responsiveness	Employee Wellness Benefit
		Reputational Risk
Innovation & Technology	Financial Performance Operational Effectiveness	Data Collection, Sharing and Reuse Benefit
		IT Capacity Risk
		IT Technical Risk
		Technological Innovation Benefit

Alectra Utilities engaged Asset Management Consulting Limited (AMCL) to conduct an independent assurance review of Alectra Utilities' Copperleaf Value Framework and business case optimization process. Furthermore, AMCL independently assessed Alectra's Value Framework against asset management best practice.

AMCL's review focused on:

- Alectra Utilities' development of the value framework
- Evaluation of project options against the value framework
- Alectra utilities' development and application of the constraints and objectives applied to the portfolio optimization within the Copperleaf software
- The financial controls and change management controls relating to the optimized portfolio

On completion of the independent review, AMCL concluded that Alectra Utilities has developed a Value Framework that demonstrates clear alignment between the OEB's RRF four outcomes and its asset decision-making, and that this is both appropriate and consistent with good public utility practice[48]. AMCL reviewed Alectra Utilities' business processes related to decision-making, focusing on governance and controls for business case development and approval. Overall, AMCL found the evaluation of investments and options against the Value Framework is well controlled and being consistently applied by contributors across the business.[49] AMCL concluded that Alectra Utilities has developed a comprehensive Value Framework that enables it to demonstrate alignment between the four outcomes defined in the RRF and Alectra Utilities' 5-year capital plan, and that this is appropriate and consistent with accepted good public utility practice[50]. Furthermore, AMCL found that Alecta Utilities has implemented a structured, sequential approach to asset investment planning which is well practiced, effective and aligns to accepted industry good practice[51].

For details of the report, refer to *Appendix D – Copperleaf Value Framework Assurance Review*.

[48] As per *Appendix D – Copperleaf Value Framework Assurance Review*, Page 5
[49] Ibid, Page 5
[50] Ibid, Page 14
[51] Ibid, Page 15

Value Measure: Investment Cost

The investment cost value measures the annual expenditure of a proposed business case. Alectra Utilities facilitates multi-constraint optimization by categorizing each investment cost into appropriate OM&A and capital costs. The SME specifies the detailed budget details, such as labour, vehicle, training, as appropriate into Copperleaf for each business case. The total cost of the project is the investment cost as illustrated in Figure 5.3.1 - 5. This investment cost value is a negative value and detracts from the overall project value.

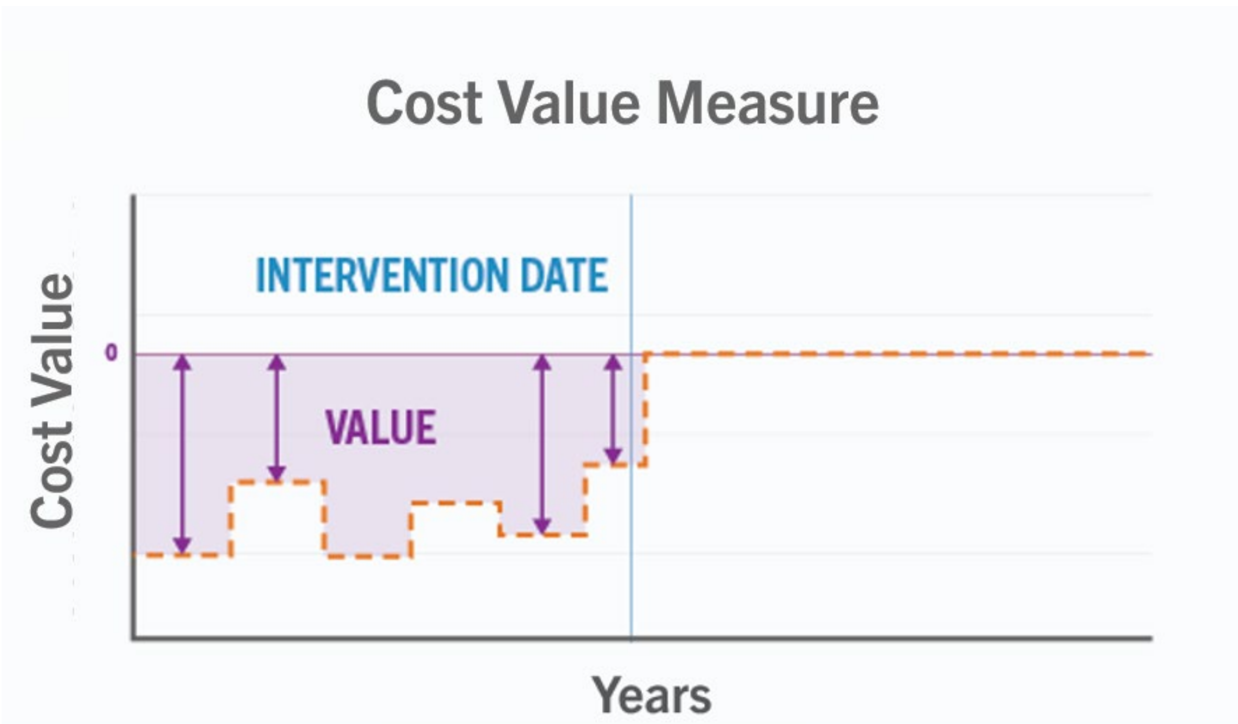

Figure 5.3.1 - 5 Value Measure - Investment Cost

Value Measure: Benefits

Alectra Utilities applies a comprehensive value-based assessment to evaluate capital investments, ensuring that each business case delivers measurable benefits while ensuring financial prudence. For example, a cable replacement project business case quantifies reliability benefits as the reliability improves after the intervention date, as illustrated in Figure 5.3.1 - 6. This approach enables a balanced evaluation of investment trade-offs. By quantifying the key benefits, Alectra ensures that capital is allocated to projects that provide the greatest value. The Benefit Value Measures used by Alectra Utilities are described in *Appendix C - Alectra Value Framework Definition Document*.

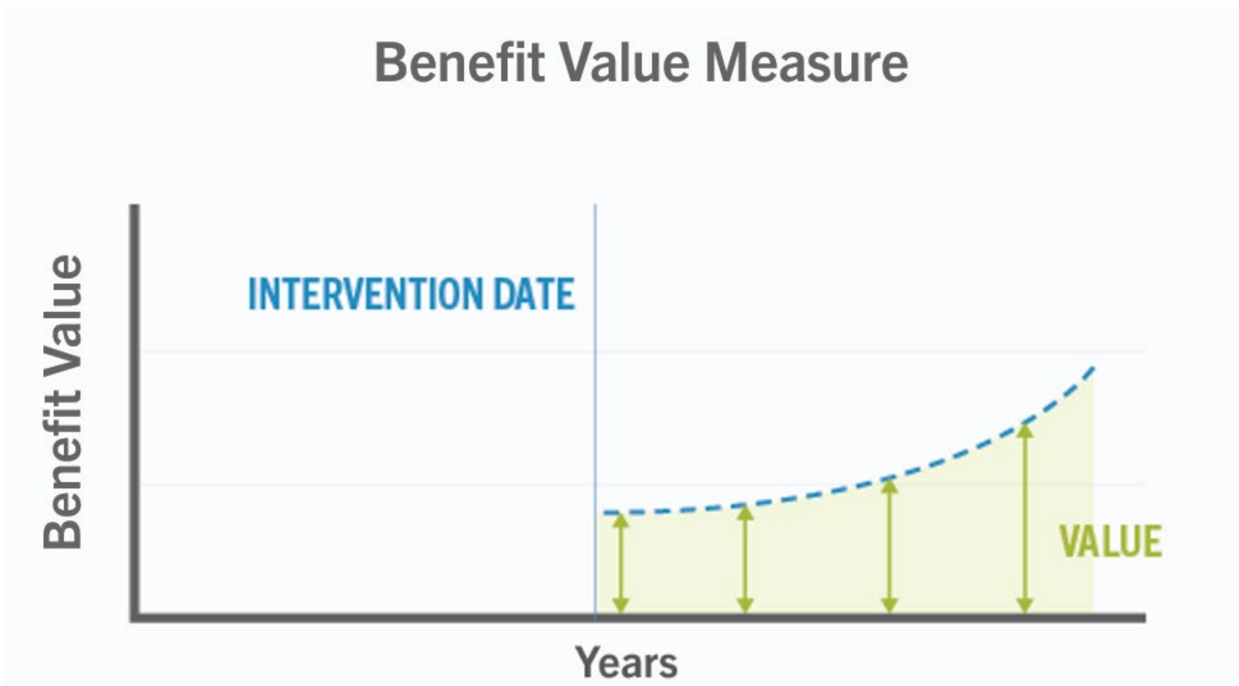

Figure 5.3.1 - 6 Value Measure - Benefit

Value Measures: Risk Mitigation

In developing each business case, the project owner maps each risk corresponding to the applicable risk categories. The Risk Value Measure considers both baseline risk as well as the remaining residual risk. Baseline risks present the risk value if the project is not completed. The residual risk presents the remaining risk value after the project is completed. The value of the mitigated risk is computed as the reduction of the baseline risk by the value of the residual risk as illustrated in Figure 5.3.1 - 7. For each risk, the business case project owner specifies the consequence (i.e. risk impact) as well as the probability of occurrence. The Risk Mitigation Value Measures used by Alectra Utilities are described in *Appendix C - Alectra Value Framework Definition Document*.

Figure 5.3.1 - 7 Value Measure - Risk Mitigation

The Risk Value measures are aligned with Alectra Utilities' Enterprise Risk Management (ERM) Policy to ensure consistent risk assessment and management. The ERM Policy, which applies to all levels of employees, guides the company in identifying, analyzing, and managing business risks. Key principles include a comprehensive and ongoing risk management process, a responsibility shared across all functional areas, integration of risk assessment in major business decisions, and maintaining transparency.

Within investment cost, benefit, and risk mitigation measures, the Net Value is determined such that benefits and risk mitigations add value, while costs reduce value. The value measures for each project are computed for each applicable year. For every business case, the net values are then converted into a single number by calculating the Present Value (PV) of the stream, back to the beginning of the current fiscal year, using a consistent discount rate. If a business case has a negative NPV, the cost of the business case outweighs its benefits.

B.1.2.2 Investment Planning Groups

To assist in compartmentalizing and categorizing the wide range of business cases in the register, planning groups are created to apply specific constraints on a subset of business cases. Alectra Utilities applies planning groups during the optimization process to identify mandatory, ongoing, and time-dependent projects. Alectra Utilities designated four planning groups to manage projects with different levels of scheduling flexibility for the multi-year CIP underpinning the DSP:

a) **Exclude**: Projects that do not have any anticipated expenditures before 2031.

b) **Must Do**: Projects that are required to be executed as a result of regulatory, contractual, legal and safety reasons. Capital investments in this group include system access (e.g. new connections, road authority) as well as reactive and emergency replacements.

c) **In-flight Not Pausable**: Multi-year capital investments that are currently under construction/implementation and require Alectra Utilities to complete. Projects may include construction of a new transmission station where a pause in construction is not feasible.

d) **Must Do Something**: Capital Project and Program investments that are paced according to: asset condition; customer needs, priorities and preferences; cost; reliability; risk levels; system constraints; and resources required to execute the work. The optimization process will select an alternative with respect to the pacing that optimizes the value of the portfolio.

During the stakeholder review process of the Copperleaf register, Alectra Utilities' management reviewed the business cases and ensured the appropriate classification of planning groups.

B.1.2.3 Optimization Constraints

To optimize the multi-year capital investment portfolio, Alectra Utilities establishes constraint limits for the optimization process, including maximum capital and operating expenditure levels, resource levels, and time constraints aligned to the planning period. This section outlines the process Alectra Utilities applied in establishing optimization constraints.

a) Capital Expenditure Constraint

In establishing capital expenditure optimization constraints, Alectra Utilities was informed by the application of the Efficiency Frontier methodology. The Efficiency Frontier is an established economic concept that provides an optimal investment portfolio level to yield the highest possible expected value for expenditure relative to a defined set of risks. The outcome of the Efficiency Frontier process guided Alectra Utilities in balancing the impact of expenditures to the expected investment value, relative to a defined set of risks. Portfolio scenarios that resulted in values below the Efficiency Frontier lower boundary were considered suboptimal because such scenarios did not yield a sufficient expected value for the level of investment. Portfolio scenarios that resulted in values above the Efficiency Frontier upper boundary were also considered suboptimal because such scenarios did not result in sufficient incremental expected value for the incremental level of investment (i.e. demonstrating diminishing returns).

b) Operating Expenditure Constraint

In addition to establishing a capital expenditure constraint, Alectra Utilities has also incorporated an Operating Expenditure (OPEX) constraint for the optimization of the multi-year capital investment plan. The benefit of including an OPEX expenditure constraint is the improvement to the optimization of capital investments portfolio for business cases that also include OPEX expenditures. In addition to capital expenditures, business cases may include elements such as on-going maintenance and licensing costs, as examples.

c) Labour Constraints

Alectra Utilities ensures that the optimized CIP is achievable with the inclusion of a labour constraint parameter in optimization. Yearly labour hour constraints for operations crews are essential for maintaining a balanced workload throughout the year while optimizing investment pacing. Labour constraints support the development of a CIP that balances value with execution capability, reduces employee turnover and ensures that Alectra Utilities Capital operates prudently and pragmatically, facilitating efficient capital work execution.

d) Planning Horizon Period

The optimization time bound was constrained to 2031, which is the final year of the DSP planning period. Projects not selected for the optimized portfolio were deferred beyond 2031 (i.e. 2032 start year).

B.1.2.4 Risk of Deferring Investments

Alectra Utilities management reviewed each iteration of the Copperleaf optimized capital investment portfolio, evaluating the implications of deferring certain projects beyond the 2031 planning period and accepting alternative scheduling simulated by the Copperleaf optimization process. Alectra Utilities management ensured that the relevant risk of deferring investment was mitigated through alternative approaches, including ongoing monitoring, inspection, transfer of risk or other appropriate risk management solutions.

B.2 Customer Preferences (Customer Engagement – Phase 2)

Following the optimization and development of the draft capital plan, Alectra Utilities engaged Innovative Research to conduct a second round of customer engagement to present customers with a fully costed plan investment options and trade-offs pertaining to the utility's draft CIP.[52] Alectra Utilities provided customers with the following information for each capital investment category to ensure informed decision-making:

- A description of the proposed investments, including the types of assets involved and the intended benefits of renewal or expansion
- Projected costs associated with each investment level, detailing the financial impact on the overall capital investment portfolio
- Estimated bill impacts, illustrating how different spending levels would translate into customer rates and affordability considerations

[52] The second phase of customer engagement was a separate process from the first phase customer engagement, which identified customers' needs and priorities, leading to the first step of the capital investment planning process.

- Outcome trade-offs, showing the potential implications of increasing or decreasing investment levels on grid reliability, service quality, and future system needs

These surveys enabled customers to customize the spending levels of various planned investment categories while highlighting the expected bill impact to the customer as a result of their choice. The results of this feedback were taken into consideration by adjusting investment categories' spending levels as a response to customers' input.

The second phase of customer engagement sought customers input on the following six capital investment areas:

1. Overhead & Transformer Renewal
2. Underground Renewal
3. Meter Replacement & Renewal
4. Fleet, Facilities & Information Technology
5. Meeting Growing Electricity Demand
6. Enabling Resiliency and Modernization

During this stage, Innovative Research presented customers with the option to adjust investment levels as an expression of the bill impact on a sliding scale and the opportunity to express their preferences based on meaningful trade-offs between outcomes that matter to them. Customers were presented with multiple options based on the range of reduced, optimized and accelerated investment pacing, as shown in Figure 5.3.1 - 8.

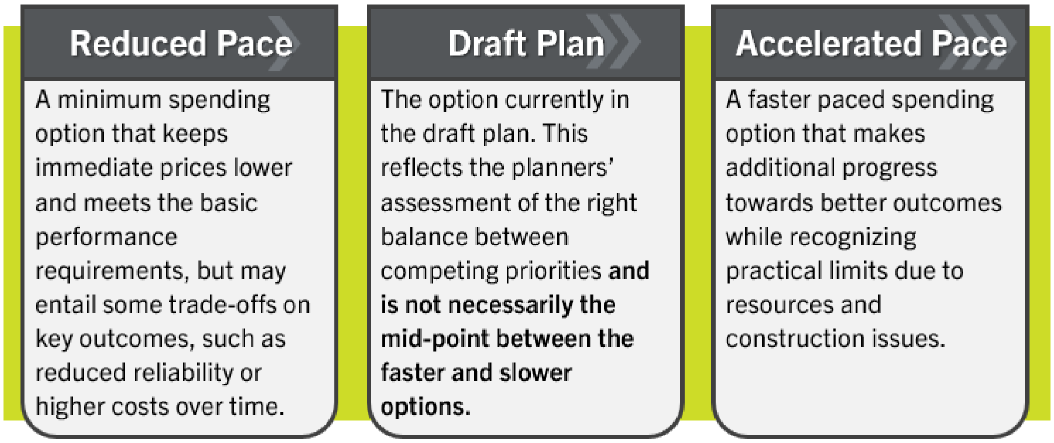

Figure 5.3.1 - 8 Spending Options to Customers

To facilitate meaningful feedback on a large portfolio of capital investments, Innovative Research developed a comprehensive workbook to outline the overall scope of the DSP and provide context to inform customers on the investment needs and solution options.

The workbook was designed to allow customers to consider their individual investment choices after reviewing the total rate impact of their initial selections.

Each Alectra Utilities customer with an email on record received an invitation containing a unique link to the workbook survey. To ensure every customer had the opportunity to express their feedback, Alectra Utilities offered a voluntary pathway for customers to participate in the online workbook and communicated this opportunity through social and traditional media.

B.2.1 Key Findings based on 2nd Phase Customer Engagement Results

The second phase of customer engagement received a record number of responses. Alectra Utilities received responses from 48,770 customers in the second phase of engagement. Across all rate classes, 86% of customers provided social permission to proceed with the draft plan. The engagement process itself was well received by customers. An average of 82% of customers had a favourable impression of the engagement survey and 75% felt that the amount of information provided was appropriate.

The key findings of the second phase customer engagement results are presented below in Table 5.3.1 - 5 (refer to *Exhibit 1, Tab 5, Schedule 2 Application-Specific Customer Engagement* for details).

Table 5.3.1 - 5 Customer Engagement Phase 2 Key Insights

DSP Investment Themes	2nd Phase Customer Engagement Choices	Key Findings
Renewing and Replacing Infrastructure	Overhead & Transformer Renewal	All customer classes except for Large Use requested increased spending in this grouping. The average from all classes resulted in customers collectively asking for no change in spending vs. plan.
	Underground Renewal	All customer classes asked for a slight reduction; the average of all rate classes was a 5% reduction in spending.
	Meter Replacement & Renewal	All customer classes asked for a slight reduction; the average of all rate classes was a 5% reduction in spending.
	Fleet, Facilities & Information Technology	The average response from all rate classes was a 1% reduction.
Meeting Growing Electricity Demand	Meeting Growing Electricity Demand	The average reduction from all rate classes was 2%.
Enabling Resiliency and Modernization	Enabling Resiliency and Modernization	The average from all classes resulted in customers collectively asking for no change in spending vs. plan.

B.2.2 Finalize Capital Investment Portfolio

Alectra Utilities incorporated customer feedback on the six investment areas from the second customer engagement by adjusting the draft plan:

- Accelerated investment in overhead asset renewal
- Reduced investment in system expansion
- Reduced investment in cable replacement
- Reduced investment in deployment of AMI 2.0 meters

The overall adjustment to the draft plan resulted in a net reduction of $106MM of expenditure over the 2027-2031 period. Alectra Utilities structured engagement methodology ensured that customers were actively involved in shaping the CIP and ultimately the DSP, reinforcing Alectra

Utilities' commitment to customer-focused capital investment decisions in alignment with the OEB's RRF outcomes.

<u>B.2.3 Inclusion of CIP into multi-year Financial Plan and Approval</u>

After the CIP is finalized, the plan is presented to Alectra Utilities' Executive Management team, which is then incorporated in Alectra Utilities' Five-Year Financial Plan for consideration and approval by Alectra Utilities' Board of Directors.

C Stage 3 - Work Execution

Once Alectra Utilities approves the Financial Plan and the finalized CIP, the next stage of Asset Management Process involving the execution of work. Figure 5.3.1 - 9 illustrates the key steps in the Work Execution phase of Alectra Utilities' Asset Management Process, specifically: Portfolio Level Project Scheduling, Project and Work Planning, Work Execution, and Project Monitoring and Control. During this phase, projects and/or initiatives that form part of the approved CIP are completed according to the approved business cases (including scope and budget). The Capital Plan execution is managed by the Program Delivery Group (PDG). For greater details of the Capital Work Execution Plan, refer to *Section 5.3.1.3.*

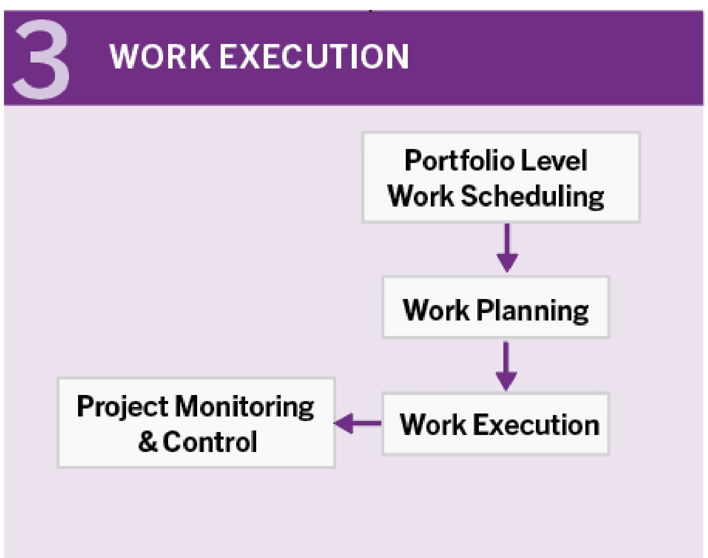

Figure 5.3.1 - 9 Work Execution

C.1 Portfolio Level Project Scheduling

Alectra Utilities utilizes Primavera P6 software to ensure a standardized process for planning and monitoring work execution progress. This integrated work planning and scheduling process provides a consolidated view of construction work and allocation of capital work to crews. The resulting benefits include enhanced ability to manage construction projects and asset procurement, leading to increased customer satisfaction and productivity improvements.

C.2 Project and Work Planning

In the planning and scheduling task, Alectra Utilities estimates work with reasonable accuracy, based on the most recent and best information available at the time, including the duration of time required for design, permitting and construction. To minimize the risk of delays of construction starts, detailed designs are completed six to twelve months in advance. Alectra Utilities completes designs in advance to ensure sufficient time is provided to provision materials, work permits and address all other prerequisite matters This is done to accommodate the processes for obtaining all necessary work permits and obtaining materials.

C.3 Work Execution

Alectra Utilities executes capital project design and construction through a combination of internal resources and external contractors. The company has entered into multi-year engineering procurement, and construction master service agreements to ensure resources and materials are available to execute the scheduled work.

C.4 Project Monitoring and Control

The planning and scheduling process is an important tool supporting Alectra Utilities in executing all distribution capital and maintenance work on-time and on-budget. The process incorporates continuous project control and monitoring capabilities as discussed in *Chapter 5.2.3 Performance Measurement for Continuous Improvement*.

D Stage 4 - Continuous Improvement

In alignment with the RRF, Alectra Utilities is committed to continuous improvement and operational effectiveness. The fourth stage of the Asset Management Process focuses on continuous improvement. As shown in Figure 5.3.1 - 10, Alectra Utilities' continuous improvement process features the following components:

1. Review Work and Project Deliverables,
2. Monitor and Report on Performance Measures
3. Develop Continuous Improvement Actions
4. Update Alectra Utilities Value Framework, Performance Targets, Process & Procedure

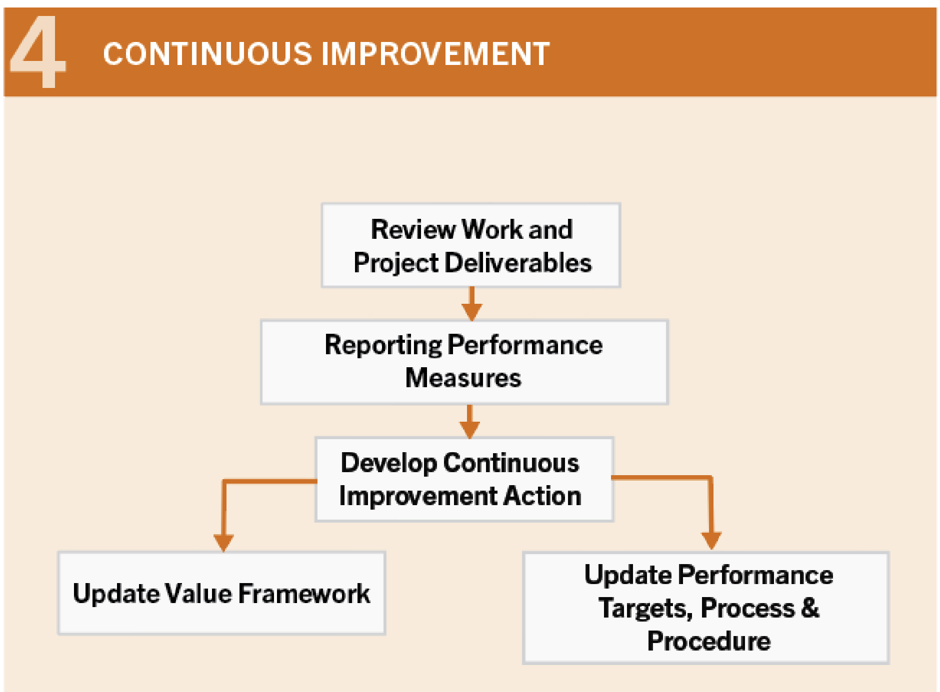

Figure 5.3.1 - 10 Continuous Improvement

D.1 Review Work and Project Deliverables

On a monthly basis, Alectra Utilities monitors year-to-date, projected year-end expenditures and in-service additions, to identify deviations from the work plan and then takes appropriate corrective actions. This includes initiating a variance review when project spending is expected to materially deviate from the approved budget.[53] Where required, projects can be scaled back,

[53] Greater then 10% variance and over $100k

cancelled, or otherwise adjusted to reflect the new circumstances and up-to-date information. The utility's senior management reviews program variances monthly and considers the approval of resource allocation adjustments as needed.

D.2 Reporting Performance Measures

Alectra Utilities monitors and reports on relevant project execution metrics, including the implementation of its capital work and reviews of trends, observations, and progress through ongoing production meetings held for each operating area with all stakeholders.

D.3 Develop Continuous Improvement Action

On an ongoing basis, Alectra Utilities identifies process improvements or modifications (either to an entire process or specific components). These changes may stem from lessons learned from recently completed projects, or from shifts in priorities due to changing internal and external drivers.

D.4 Update and Calibrate Value Framework

Alectra Utilities management reviews the value framework annually to ensure that value measures align with public policies; corporate objectives; emerging technologies and productivity initiatives. Alectra Utilities calibrates its Value Framework with the Corporate Enterprise Risk Management (ERM) Register to ensure consistency across the organization.

D.5 Update Performance Targets, Processes and Procedures

In this step, Alectra Utilities' Asset Management group gathers feedback from internal and external stakeholders and project leads on the questionnaire used for scoring projects in order to determine if adjustments or calibration is required to capture all relevant and up-to-date investment values and measures appropriately.

5.3.1.2 Planning Process Data

This section outlines the various inputs and systems that inform the utility of investment needs and requirements as per Alectra Utilities' Asset Management Process. These systems and inputs provide a crucial role to ensure informed, data-driven decision-making with comprehensive insights into asset performance, condition, and lifecycle requirements and development of investment business cases. The following key systems are used to capture, assess, organize, update and maintain relevant data sources, as further explained below:

A Asset Condition Assessment and Inspection Data

Alectra Utilities' Asset Condition Assessment (ACA) and Predictive Analytics (PA) leverage data analytics and rigorous inspection protocols to develop an in-depth understanding of its asset portfolio's health. Partnering the ACA with other Asset Management practices, including the Asset Analytics Platform (AAP), enables timely and proactive investment decisions to drive reliability improvements and mitigate numerous risks (safety, environment, compliance)

A.1 Asset Analytics Platform

Alectra Utilities uses an Asset Analytics Platform (implemented in 2020 using Alteryx) to compute asset condition assessments. The AAP enables Alectra Utilities to compute asset condition assessments, overlay reliability data sets with maps to identify emerging hotspots, and combine large datasets to establish correlations. Data from multiple sources is integrated and analyzed for Asset Condition Assessment. Alteryx consolidates reliability data, asset condition information, spatial data (GIS), and CYME system data (including short circuit values, customer counts, and kVA ratings). This integration enables the creation of feature-rich and data-dense maps that provide a comprehensive visualization of asset health, system performance, and localized reliability information. By unifying these datasets, Alectra Utilities improves risk assessments, identified emerging infrastructure issues, and optimized capital investment planning with greater accuracy and efficiency.

Results from inspection, testing, and maintenance programs are inputs to Alectra Utilities' ACA, which ultimately establishes Health Index (HI) values for eleven major asset groups. The result indicates the asset condition across the HI spectrum, ranging from "Very Poor" to "Very Good". Further information regarding the ACA is presented in *Chapter 5.3.3 Asset Lifecycle Optimization*

Policies and Practices and in the Asset Condition Assessment Report (refer to *Appendix E - Asset Condition Assessment Report*). The ACA is based on inspection data recorded at the end of 2023.

A.2 Predictive Analytics

Alectra Utilities applied condition data and failure rates for an asset class to establish long-term projections, leveraging Copperleaf Asset Software. Copperleaf Asset is an application that utilizes predictive analytics to determine the optimal timing for asset replacement, based on asset condition, reliability, safety, and financial risks associated with asset failure. The results of the analysis were appropriately paced at different investment levels, considering Alectra Utilities' pacing options of Accelerated, Moderate, or Reduced pacing, and serve as alternatives for asset renewal investment business cases for CIP optimization. For further details, refer to *Chapter 5.3.3 Asset Lifecycle Optimization Policies and Practices*.

B Reliability Data

Alectra Utilities applied reliability data to analyze emerging trends in system reliability and performance. The AAP was leveraged to consolidate, analyze and report on various key parameters detailed below and is critical to various Asset Management Processes utilized to drive data-informed investment decisions.

B.1 Asset Analytics Platform

Alectra Utilities utilized Alteryx to enhance reliability analysis and reporting by integrating GIS data, Outage Management System (OMS) information, and equipment failure information. The platform streamlines internal reliability reporting, OEB compliance reporting, and defective equipment tracking, enabling a centralized and automated approach for obtaining reliability analytics. By linking outage data with asset performance metrics, Alectra Utilities completes detailed failure trend analysis, identifies of recurring equipment issues, and tracks defective assets. This integration of multiple data sources into one platform informs proactive maintenance strategies, targets asset replacements, and improves decision-making to enhance system reliability and reduced outage impacts.

B.2 Outage Management System

Alectra Utilities utilized its OMS systems to obtain system outage data, which is used as input for system reliability and worst feeder performance analysis. These analyses are the primary internal drivers for the Asset Management Process. The OMS provides a crucial role in identifying, tracking, reporting, and facilitating the restoration of power outages. The OMS utilizes the GIS connectivity model and integrates inputs from smart meters, SCADA, Customer Information System (CIS), Interactive Voice Recognition (IVR), and manual input to deliver real-time, dynamic information on system outages and status. All input on outage calls, whether collected automatically (e.g. from smart meters) or manually, is grouped to provide dynamic network performance information, including real-time outage notification alerts and key reliability statistics. Regular asset performance and operational reports, which are generated from OMS data, are reviewed to ensure informed decision-making. The reliability data used in this application is current up to the end of 2024.

C Load Forecast

Alectra Utilities utilized its Load Profiling and Settlement System to acquire wholesale settlement data from the IESO, determining the loading on the Transformer Stations (TS) from 2019 to 2023. The settlement data is retrieved from the IESO's secured report site, which contains interval wholesale meter data installed at the TS to track the energy Alectra Utilities withdraws or injects into the IESO-controlled grid. Furthermore, Alectra Utilities applied Supervisory Control and Data Acquisition (SCADA) data to cross-verify and reconcile with the wholesale metering information, ensuring the accuracy of the data. The SCADA system was also used to retrieve the hourly feeder loading and Municipal Stations (MS) data from 2019 to 2023. The housing and Industrial, Commercial, and Institutional growth projections for the load forecast were obtained from the most recently published Municipal Development Charge reports[54], which were published the period from 2019 to 2023. The CDM growth projections were obtained from the Integrated Regional Resource Planning reports[55] published by the IESO, which were published the year 2019 to 2023.

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[54] Refer to *Chapter 5.3.2 (Section 5.3.2.1 B.1)* for a full list of reports
[55] Refer to *Appendix H - Regional Planning Reports* for the Integrated Regional Resource Planning Reports

The EV growth projection[56] from 2022 to 2040 was developed in collaboration with Guidehouse Inc. in 2022.

D Climate Risks

Alectra Utilities engaged Hatch Ltd. to conduct a Climate Risk and Vulnerability Assessment (refer to *Appendix G - Climate Risk & Vulnerability Assessment*), which leveraged data from:

- Intergovernmental Panel on Climate Change (IPCC) [57]climate scenarios to model the impact of evolving weather patterns within Alectra Utilities service area. The study examined three climate scenarios; refer to the study for details on the climate scenarios.
- Alectra Utilities' outage data from 2019-2023
- Alectra Utilities Major Event Reports from 2019-2022
- Historical Weather Data
- Specialized climate studies

Alectra Utilities further utilized the study to inform its asset-based approach to identifying climate-vulnerable assets (refer to *Chapter 5.3.2.1 C – Climate Trends*) with Pole asset data to identify climate-vulnerable poles based on geographical location and other relevant asset attributes.

[56] Refer to *Appendix J - Load Forecast & System Capacity Adequacy Assessment Report* for the EV growth projection
[57] https://www.ipcc.ch/

5.3.1.3 Capital Work Execution

A Introduction

A critical component of the Asset Management Process is the execution of work. This section describes how Alectra Utilities does and will execute its capital programs. Alectra Utilities' approach focuses on:

- A robust Capital Delivery Process that sets portfolios (e.g. with project-level scheduling) based on investment needs (e.g. customer and system needs) and optimized planning, and makes necessary adjustments based on dynamic factors (e.g. emerging issues) and constraints
- Labour Resources, both internal and external, required to complete the work
- Work Enablers, including availability of materials and fleet resources, outage scheduling, site conditions, and safety

Alectra Utilities' approach to work execution has effectively delivered annual capital programs during the Historical Period (2020-2024) despite dynamic customer and system needs, as evidenced in *Chapter 5.4.1 (Section 5.4.1.2*). Throughout this period, Alectra Utilities met System Access requirements, maintaining better-than-target service requirements for the Connection of New Services in all years, while managing a substantial increase in volumes and delivered on an increasing System Renewal program.

Alectra Utilities' approach to successfully delivering its capital plan and scaling to meet changing requirements is the foundation from which Alectra Utilities will execute its 2027-2031 plan. The following provides details on each of the aforementioned focus areas.

B Capital Delivery Process

Alectra Utilities' Capital Delivery Process is of critical importance to the effective execution of the utility's capital work. The Capital Delivery Process is a subset of Alectra Utilities' Asset Management Process, which is detailed in *Section 5.3.1* (for ease of reference, the Asset Management Planning Process, and its four stages are illustrated in Figure 5.3.1 - 11) Specifically, the Capital Delivery Process refers to the third and fourth (i.e. Work Execution and Continuous Improvement, respectively) stages of the Asset Management Process (refer to *Section 5.3.1.1 C* and *Section 5.3.1.1 D*).

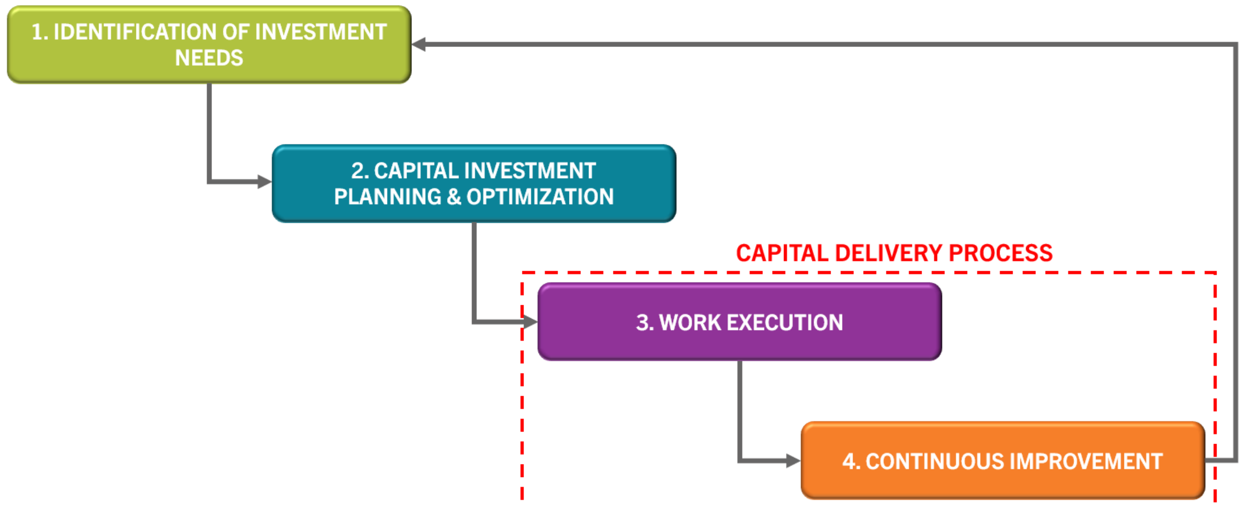

Figure 5.3.1 - 11 Alectra Utilities Asset Management Planning Process Stages, Including Capital Delivery Process

B.1 Capital Delivery Process: Work Execution

The Capital Delivery Process takes portfolios of work and specific projects (as outputs from Alectra Utilities' Investment Planning & Optimization), and moves them through the phases of Work Execution, namely: (i) Design and (ii) Construction. Projects are to be completed in accordance with approved scopes and budgets. Oversight of the Capital Delivery Process is handled by Alectra Utilities' Program Delivery Group (PDG), which utilizes Primavera P6 software to ensure standardized and robust planning and monitoring of work. The PDG maintains a consolidated view of projects and the resources allocated to completing those projects.

As noted above, each project consists of the (i) Design and (ii) Construction phase. Detailed designs are typically completed six months to a year in advance of construction. This allows Alectra Utilities to obtain the necessary work permits (e.g. those granted by road authorities and municipal or city agencies), to secure materials, and to effectively bring forward or push out specific projects (when necessary, due to dynamic conditions and constraints) without affecting overall productivity and program delivery. As Alectra Utilities' capital program has grown over the last five years, particularly in System Access (i.e. 61% growth) and System Renewal (i.e. 27% growth) categories, it has become that much more important to coordinate and plan projects in alignment with necessary resources (i.e. labour, external vendors, materials). The PDG tracks both (1) "controllable" (or "planned") and (2) "unplanned" (or "demand") work and applies the following approaches and tools to ensure projects are executed according to approved scope, on time, and on budget:

(1) Controllable Work

- System Renewal and System Service projects are assessed (by unit quantities or budgetary estimates, historical averages, known crew compositions and labour hours) to attain approximate schedules for labour resource demand.
- Potential constraints (e.g. permit requirements, seasonality of work, relative urgency of completion) are used to assign crew schedules.
- Work that exceeds internal labour resource capacity, or is better aligned with external resource skills, is identified for release to external contractors.
- Following the completion of detailed designs, the PDG confirms material availability, crew availability, and any constraints (e.g. outstanding permits), before implementing a final schedule and assembling work packages for construction crews.

(2) Unplanned Work

- For System Access projects, budgeted work amounts, seasonal demand levels and historical labour usage are utilized to forecast and schedule (or reserve) the expected resource demand.
- As customers request work to be completed, schedules are refined, and once work is committed (e.g. through accepted Offers to Connect) and conditions have been met, projects are executed by crews.
- For Reactive work (within System Renewal) trouble and other crews perform repairs and corrective maintenance, along with associated activities (e.g. switching, equipment outages).
- If Unplanned Work volumes are lower than forecasted, crews are redirected to planned work.

The Planning and Scheduling team (within the PDG) manages the various project management functions discussed above with respect to the capital program. This team is supported by a Results and Reporting team, which manages Alectra Utilities' portfolio management software platform (Oracle's Primavera P6 Cloud) as well as various Business Intelligence dashboards and reporting systems (e.g. Microsoft PowerBI) that provide near real-time situational awareness of the capital programs and projects, as well as an Operational Process Improvement team that identifies, supports and implements productivity improvements within the capital and maintenance programs.

This team has successfully and productively managed a growth of approximately 45% in their managed capital portfolio between 2021-2024. This has been achieved through a combination of automating various reporting functions and harmonizing work processes across operational centres.

To meet the demands of Alectra Utilities' capital program outlined in the Distribution System Plan, for the 2027-2031 period, the PDG must expand to include a modest number of additional resources. In addition, the PDG will continue to invest in automating reporting functions and preparing advanced dashboards to efficiently manage a larger portfolio of capital work.

B.2 Capital Delivery Process: Project Oversight, Closure, and Continuous Improvement

The PDG, as part of the Capital Delivery Process, documents project deviations through Alectra Utilities' red-lining and Request For Change (RFC) processes. These processes ensure that impacts on standards, materials, labour demands, project costs and schedules are captured and assessed through a review and approval process.

Throughout construction, Project Coordinators who are assigned to execute specific work packages, provide weekly updates on active projects, track adherence to schedule and the achievement of project outcomes. In addition, regular meetings are held with stakeholders in Operations, Design, Supply Chain and Asset Management to review project and program progress and address risks.

Once construction is completed, the PDG performs and monitors various project closure processes such as material returns, final invoicing, confirmation of completed as-built drawings, and records of inspection.

These monitoring, controlling, and closing processes are critical to ensuring project scope, budget and schedule controls are in place and adhered to, as well as to ensure continual improvement learnings are utilized for future projects. These processes ultimately support Alectra Utilities in achieving the objectives of its capital program, while adhering to financial controls, engineering and construction best practices and meeting critical delivery dates.

C Factors Impacting Work Execution

C.1 Labour Resources

The nature of Alectra Utilities' capital program, and in particular the work associated with System Access, System Renewal, and System Service investments require a wide variety of labour resources. The following discusses resourcing considerations and approaches for four of the most critical labour resource groups, namely: (a) Lines, (b) Stations & P&C, (c) Control Room, and (d) Distribution Design. Together, these four groups contribute to just under 90% of 2027-2031 planned capital investments (additional details about these resource groups and others across Alectra Utilities that contribute to work execution can be found in *Exhibit 4, Tab 3 Workforce Staffing Plan & Strategy*).

Alectra Utilities executes capital project design and construction through a combination of internal resources and external contractors. The company has engineering, procurement and construction agreements to ensure resources and materials are available to execute the scheduled work.

C.1.1 Lines Execution Resources and Approach

Lines resources are responsible for the field operation, maintenance, and construction of the distribution system. Examples of the work undertaken by Lines resources are:

- Trouble response and repairs on distribution lines
- Inspections and maintenance of overhead and underground lines
- Replacements of distribution transformers
- Overhead pole and underground line rebuilds

Lines resources are responsible for completing approximately three quarters of Alectra Utilities' capital programs, the totals of which are illustrated below for the 2020-2031 period.

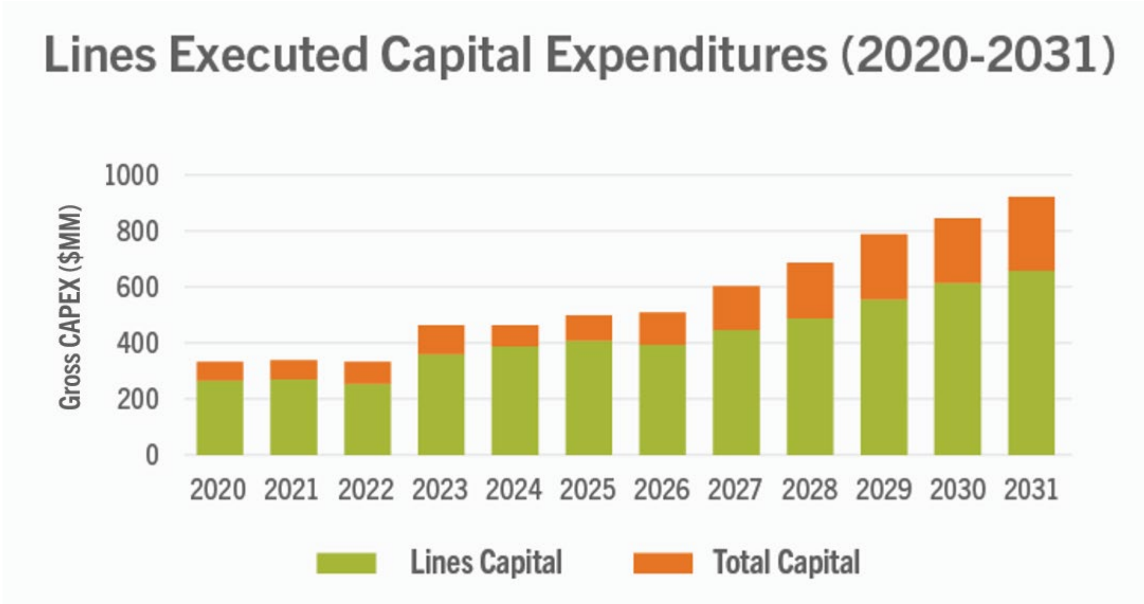

Figure 5.3.1 - 12 Lines Executed Capital Expenditures (2020-2031)

To effectively resource the execution of Lines work, Alectra Utilities must balance the availability of internal lines (e.g. powerline technicians) and external contractor resources. As evidenced in the chart above, Alectra Utilities has effectively managed this balance, which has enabled Lines resources to execute an increasing capital program over the 2020 to 2024 (i.e. increasing from a gross capital expenditure of $265MM in 2020 to $388MM in 2024). What follows provides information on how Alectra Utilities approaches this balance and how this balance will enable Alectra Utilities to deliver the 2027-2031 capital program.

Beginning with internal resources, Alectra Utilities maintains a core group of highly skilled internal staff (e.g. powerline technicians). As detailed in *Exhibit 4, Tab 3 Workforce Staffing Plan & Strategy*, Alectra Utilities averaged 384 internal resources focused on overhead and underground lines over the 2021-2024 period. This group is strategically important and as system needs (and the responsive capital program) grow, Alectra Utilities plans to invest and grow internal resources to 466 resources. This will be done in a sustainable and prudent manner that considers safety, training, cost effectiveness, and other imperatives.

Regarding external contractor resources, contractors are essential as they deliver on work that requires (i) more resources than Alectra Utilities' internal resource capacity can meet or (ii) specialized skillsets or equipment that is beyond what is available within Alectra Utilities. For the purposes of the 2027-2031 capital program, Alectra Utilities conducted a thorough analysis of Lines capital execution needs to determine the extent of external contractor support required. That analysis entailed the following:

A. Historical actual labour information was used to determine the number of lines (i.e. powerline technician) labour hours required to support each project in the Distribution System Plan by region; and

B. Long-term planning discussions were held with Alectra Utilities' lines contractors (i.e. construction partners) to carefully understand current and future capabilities and capacities with respect to a major capital program ramp up.

The outcome of the analysis confirmed the executability of the 2027-2031 capital programs. Figure 5.3.1 - 13 summarizes the capacity available through Alectra Utilities' external contractors and the extent to which Alectra Utilities plans to utilize that capacity.

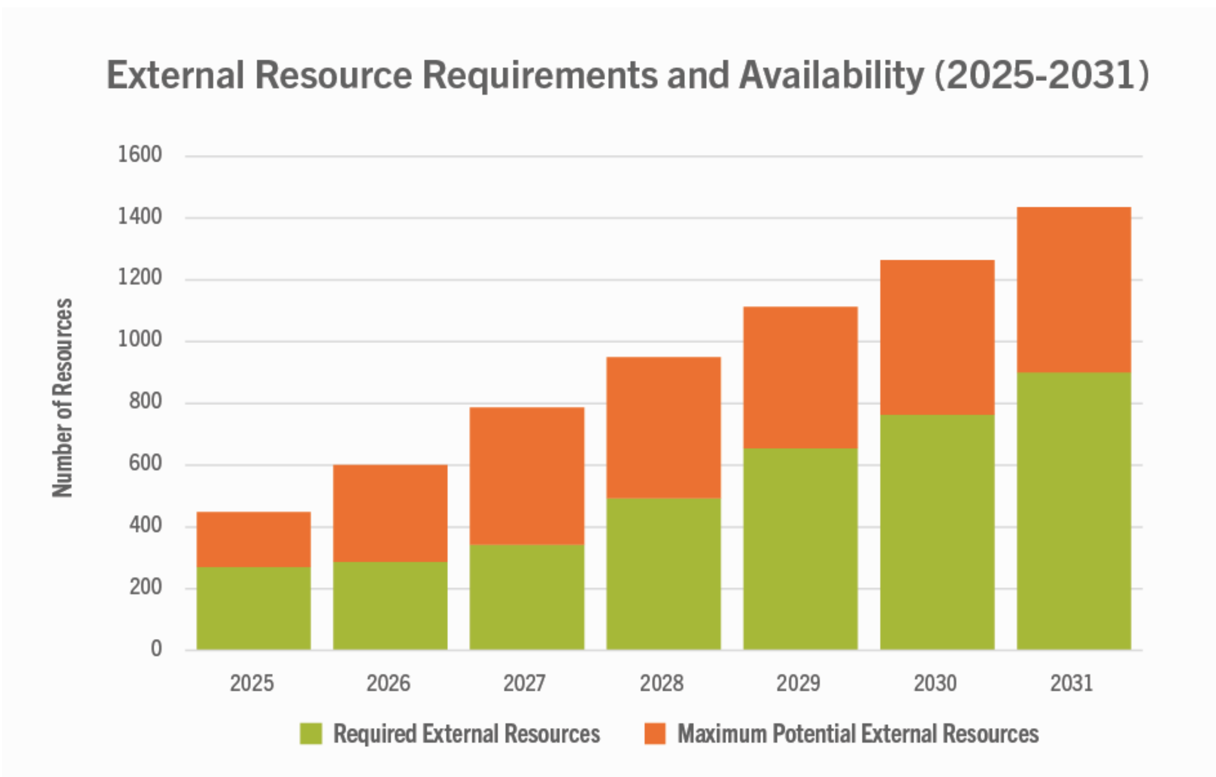

Figure 5.3.1 - 13 External Resource Requirements and Availability (2025-2031)

C.1.2 Stations Execution Resources and Approach

Station resources are responsible for the design, construction, and maintenance of transformer and municipal stations, protection and control, and telecommunications assets. Examples of the work undertaken by Stations resources include:

- Stations expansion work to increase capacity
- Replacements of switchgear and protection relays
- Deploying fibre and other telecommunications infrastructure to support SCADA and AMI 2.0 communications

Stations resources are responsible for contributing to approximately 14% of Alectra Utilities' capital program for the 2027-2031 period. Many of the projects undertaken are large, and can span several years, involving multiple stages and work groups. Analogous to Alectra Utilities' approach to Lines Execution resources, it is critical to achieve a balance between internal (e.g. Protection & Control Technologists, Station Maintenance Technicians) and external contractor resources. The following describes Alectra Utilities' approach to each.

Beginning with internal resources, Alectra Utilities has maintained an average of 66 internal stations resources over the 2021-2024 period. Similar to Lines, this group is strategically important to the execution of Alectra Utilities' capital plans. As detailed in *Exhibit 4, Tab 3 Workforce Staffing Plan & Strategy*, Alectra Utilities plans to invest and grow internal resources by approximately one third (to 89 resources). This increase is required to safely, sustainably and cost effectively undertake work such as station rebuilds, protection upgrades, telecom deployments, and distribution automation.

Contractors are currently utilized for various activities in the design and construction of Stations, Protection, and Telecom projects. Contractors will be utilized to undertake activities, such as heavy construction, that require specialized equipment and skillsets and are beyond the capacity of internal resources. In some cases, contractors will be utilized to supplement internal resources and to undertake specific tasks to support internal staff in carrying out design or field work. Contractor resources will primarily be required to perform the following tasks:

1. Design and construction of new stations
2. Design and construction of major telecom projects, such as WiMAX tower installations and fibre-optic deployments

3. Specific supporting activities on switchgear replacement and protection upgrade projects
4. Project Management, owner engineer activities, and commissioning

For the major categories of projects in this portfolio, the mix of internal and contractor resources will be as shown in Table 5.3.1 - 6.

Table 5.3.1 - 6 Project Type Resource Mix

Project Type	Design	Construction	Project Management
New Stations (TS and MS)	Contractor	Contractor Internal personnel involved in commissioning	Internal and Contractor
Station Switchgear replacement	Internal; supplemented by Contractor	Contractor Internal personnel for protection work and commissioning	Internal and Contractor
Protection Upgrades	Internal; supplemented by Contractor	Internal with Contractor assistance for specific tasks	Internal
Telecom – WiMAX	Contractor	Contractor Internal personnel involved in commissioning	Internal and Contractor
Telecom – other	Internal	Internal; supplemented by Contractor	Internal

To successfully deliver the stations, protection, and telecom capital programs and projects, it is essential that sufficient skilled, competent contractor resources be available to undertake the required design, construction, and project management activities. Internal Alectra Utilities personnel will play a key role in these activities, but significant contractor resources will also be required to execute the large volumes of work. Contractor resources will be particularly critical for delivering the new station build projects, as these are labour-intensive initiatives. Alectra Utilities will ensure skilled, competent contractor resources are secured in sufficient volumes to support the stations capital programs and their execution as planned in this DSP.

C.1.3 System Control (Room) Execution Resources and Approach

System Control resources are responsible for the real time monitoring and operation of the distribution system, and the coordination of planned work on the system. System Control is also often referred to as the “Controlling Authority” for Alectra Utilities’ distribution system, meaning that no operations of grid devices can be conducted, by either Alectra Utilities or third-party crews, without the permission and direction of System Control.

As detailed in *Exhibit 4, Tab 3 Workforce Staffing Plan & Strategy*, Alectra Utilities has been gradually increasing System Control resources, averaging 70 resources over the 2020-2024 period. The System Control function is unique in many ways to other functions including Lines, Stations, and Design, in that the opportunities to leverage external resources are limited due to the system knowledge and certification requirements to perform Control Room duties. As a result, Alectra Utilities needs to grow System Control resources by half (to 106 resources) to (i) enable the execution of the capital programs, and (ii) effectively operate an increasingly complex distribution system comprised of more Distributed Energy Resources (DERs), automated and remotely operable switches, and one that is faced with greater risk of storm and major event risks.

The execution strategy and plan for System Control was informed by various considerations including: (i) that the capital programs planned for 2027-2031 are familiar to the System Controllers and changes to the scope of responsibilities is limited; (ii) the group needs to be able to scale to match increases in field crew and construction activities; and (iii) productivity factors including training and apprenticeships, process and system harmonizations, scale, and the 24/7/365 day nature of the work.

C.1.4 Distribution Design Resources and Approach

Distribution Design Resources are responsible for developing detailed designs for capital projects prior to their construction. Examples of tasks undertaken as part of detailed design are:

- Reviewing and understanding scopes of work issued by Asset Management, to take them from concept to full design
- Engaging with customers and understanding connection requirements for developments or relocations
- Developing designs by applying Alectra Utilities’ design and construction Standards to form an Issued-to-Construction (ITC) drawing
- Obtaining necessary permits from approval agencies, such as municipal, conservation, and other third parties, to perform construction

- Performing engineering analysis and calculations such as structural strength, voltage drop, pulling tensions, necessary to ensure safety and constructability
- Establishing detailed estimates (labour, equipment, materials) for projects
- Issuing "Offer to Connect" agreements to customers
- Coordinating with Operations Supervisors and Managers with respect to constructability and project timing

Over the 2027-2031 period, work that will require detailed design resources is planned to increase by 68%. Similar to Lines and Station resources, this work will require the deployment of both Alectra Utilities' internal resources and external contractor resources.

Beginning with internal resources, as detailed in *Exhibit 4, Tab 3 Workforce Staffing Plan & Strategy*, Distribution Design resources have steadily increased over the 2020 to 2024 period, averaging 128 full-time equivalent resources. Alectra Utilities needs to grow this compliment by two thirds (to 212 resources).

Regarding external "Design Consultant" resources, Alectra Utilities plans to increase the number of external resources from 87 currently to 186 in 2031. This increase is necessary to complete the 2027-2031 programs. Similar to Lines execution resources, Alectra Utilities has mature, contractual relations with external firms that provide design resources and services. Alectra Utilities conducted an analysis and set of engagements with firms and confirmed that resources are available to meet Alectra Utilities' needs and that Alectra Utilities' 2027-2031 plans are executable. To further ensure effective execution as Alectra Utilities grows its design resources, the following activities have also been undertaken.

- Implemented design attainment, quality assurance, and quality control measures.
- Moved from issuing (to construction) 70% of the planned capital program by the end of a prior year, to issuing 100% (as monitored and tracked on a monthly basis).
- Developed a comprehensive Distribution Design Manual (DDM) to assist in onboarding and training of new internal and external design staff, which ensures consistency and compliance with Alectra Utilities' requirements leading to efficient and effective design output.

C.1.5 Other Resources - General Plant

Although Lines, Stations, System Control, and Distribution Design resources (as discussed above) contribute to (and are critical for) the execution of the vast majority of the 2027-2031 programs, Alectra Utilities relies and needs a vast number of other resources ranging from Asset Management staff and Supply Chain Services, to Digital & Innovation and Facilities professionals. This is particularly true for General Plant investments. *Exhibit 4, Tab 3 Workforce Staffing Plan & Strategy* provides additional details on all necessary resources and Alectra Utilities' Workforce Plan and Strategy.

For projects within the General Plant category, Alectra Utilities has implemented a robust Project Governance Framework, overseen by a Project Management Office (PMO) and a Transformation Management Office (TMO). This framework ensures operational excellence and strategic alignment across the enterprise. The PMO oversees project execution and delivery, while the TMO ensures projects align with Alectra Utilities' strategic goals and customer needs. This approach includes resource planning and capacity management (i.e. the identification of resource needs early in the project lifecycle), detailed cost estimates, centralized resource management tools, and visibility into resource availability and utilization across projects. Key Elements of the framework include those below.

- *Project Tiers*: Projects are categorized into four tiers based on complexity, cost, benefit, interdependencies, and risk. Each tier has corresponding requirements for project oversight, project management, documentation, and reporting frequency.
- *Project Oversight*: The governance structure includes various committees and roles each with specific responsibilities to ensure project success, resolve issues and risks and mitigate impacts on the portfolio.
- *Stage Gates*: Project delivery stage gates include Initiation, Planning, Execution & Control, and Closure. A systematic approach to determine the readiness of a project to proceed to the next set of deliverables.
- *Project Change Request*: Changes to project scope, schedule, resources, budget, benefits, or technology are assessed for materiality and potential impact on the broader portfolio. The process is governed by clearly defined thresholds and approval pathways.

- *Monitoring and Reporting*: Project and portfolio performance is tracked using standardized tools that provide both granular and portfolio-level insights.
- *Continuous Improvement*: A structured feedback loop including documenting lessons learned and best practices guides future business planning and project execution.

C.2 Work Enablers: Materials (Sourcing and Availability)

The execution of Alectra Utilities' capital programs relies on the availability of materials and equipment. For example, the material purchased to enable the 2024 capital program totaled $98.9MM in 2024, which made up 30% of net capital expenditures in that year. Given this, material purchases are a critical input, and ultimately enabler, for Alectra Utilities' capital programs. As a result, Alectra Utilities deploys a set of comprehensive strategies and processes that enable efficient and effective work execution. Alectra Utilities' ability to manage and scale its material sourcing availability can be demonstrated in the growth of material purchases. Material purchases associated with capital work in 2021 were valued at $58.7MM and grew to purchases of $98.9MM in 2024.

Beginning with sourcing strategies, Alectra Utilities employs a proactive approach to supplier management, which includes:

- Strategic partnerships
- Diversified sourcing options (e.g. multiple supplies for each part number)
- Advanced monitoring tools
- Standardized materials across locations
- Securing larger quantities of production slots from manufacturers through increased order volumes

These strategies have enabled Alectra Utilities to reduce costs, anticipate and address potential supply chain disruptions, maintain consistent material flow, and minimize the adverse effects of delays on operational performance.

From a process perspective, structured workflows in Alectra Utilities' ERP system are leveraged, along with Microsoft Power BI reports, to ensure timely and effective delivery of materials. Elements of the workflow include:

- Distribution Design resources outline the required materials for projects, including any necessary long-lead time items, and notify Supply Chain resources
- Supply Chain resources then review parts lists, check inventory levels, and confirm delivery dates to align with project timelines
- Supply Chain resources send work orders to the PDG for scheduling

Alectra Utilities uses historical trends and operational forecasts to project future material demand. This information is used to determine optimal safety stock levels and to collaborate with suppliers of key material to ensure there is appropriate production capacity to meet the needs of the business.

Alectra Utilities manages supplier performance by closely monitoring material request dates against planned delivery dates to ensure timely delivery. Alectra Utilities conducts monthly meetings with primary suppliers to review all open purchase orders and discuss any potential supply chain risks, along with mitigating strategies. Alectra Utilities has established an escalation process for tracking material delays on key equipment, which follows the equipment through the production process and escalates internally and with suppliers based on criticality. This ensures that delays are addressed promptly and effectively.

To meet the demands of the 2027-2031 Capital Investment Plan, the Alectra Utilities' Supply Chain function has engaged all major suppliers, and confirmed their ability to meet the forecasted material requirements. In addition, Supply Chain has secured long-term contractual commitments with all major distribution suppliers.

Power transformers, which are long lead-time assets, for new stations will be procured via a single RFP process to streamline the procurement process, allow the advance securement of production timeslots, and potentially realize pricing advantages. Switchgear orders for new and renewed Stations will be combined as much as possible for projects with coincident timelines, which will also streamline procurement processes.

C.3 Work Enablers: Fleet Availability

In addition to labour resources and materials, a critical enabler for the capital program is the availability of transport and work equipment, commonly referred to as the Fleet. The Fleet is utilized by Lines and Stations resources (amongst others) when conducting field work. The process of determining the required number of fleet assets was directly informed by Alectra Utilities' workforce planning activities, which identified the necessary numbers of labour resources, including Lines and Stations resources (described above).

Alectra Utilities has ensured that the fleet is adequately scaled to meet the planned 2027-2031 workload. This has been done by applying established operational benchmarks—specifically, the ratios of employees per vehicle and fleet assets per crew. These ratios are derived from historical performance data, operational experience, and industry standards, and are used to maintain consistency, efficiency, and safety in field operations.

The strategic fleet plan in *Appendix B08 - Fleet Renewal* provides a comprehensive projection of the number and type of fleet assets required to support operational demands for each fiscal year from 2025 through 2031. This projection is paired with corresponding annual budget estimates to ensure the availability of necessary resources to meet organizational objectives.

C.4 Work Enablers: Outage Scheduling and Safety

C.4.1 Outage Scheduling

The execution of Alectra Utilities' capital projects and programs often requires isolation or de-energization of a segment of the distribution system to allow the work to be safely performed. These outages could involve the de-energization of an entire station, station feeder, or just a section of the distribution system. The outages and system reconfiguration required to accommodate these outages often create operational or scheduling constraints on the distribution system. Operational constraints include capacity constraints, overloading of feeders or an impact on the system's redundancy and resilience. Managing these constraints is critical in Alectra Utilities' execution of its capital program.

To ensure these constraints are managed and do not cause delay or issue with work execution, Alectra Utilities has been enhancing its current outage planning processes by initiating the outage planning process earlier and requiring an assessment during the design phase to identify potential constraints that may be created during the execution phase of the project. Pre-requisite, or dependent projects have already been included in the planning and scheduling process, and potential capacity or loading issues, and any reduction of redundancy will be identified and used as additional inputs moving forward. Projects with capacity or loading issues are scheduled for the shoulder months, where possible, when system load is at its lowest. Identification of loss of redundancy will allow the constraint to be reviewed, the risk level identified, and contingency plans developed when the risk presented is above acceptable levels.

The second enhancement is the inclusion of a geospatial review of projects during the planning and scheduling stage. The location for each project will be overlayed on the GIS system thereby showing which projects physically overlap. Where projects physically overlap, they will then be scheduled for different periods within the year to minimize the risk of the projects conflicting during execution which would result in project delays and additional costs.

C.4.2 Safety

Alectra Utilities is committed to ensuring all staff return home safely at the end of each day. This commitment can be seen through Alectra Utilities' programs and process that ensure staff stay safe and are able to handle the risks that are associated with doing their work. These processes and programs include Near Miss reporting and investigation, Joint Health and Safety Committees, site inspection programs, and Safety Starts and Safety meetings. Each one of these programs is detailed in the following paragraphs.

Alectra Utilities drives safety through employee involvement ensuring employees have a pathway to report "Near Miss Incidents" which are an opportunity to correct a potential safety concern before it has the opportunity to become a safety incident. Each of the Near Miss report is tracked through Alectra Utilities' Intelex system, and is monitored for corrective action, closure and is shared across the organization as a learning opportunity to ensure any such potential incidents are prevented.

Alectra Utilities has a robust Joint Health and Safety Committee that is comprised of management and union members. The Joint Health and Safety Committee is broken down into smaller site-specific safety committees. Each of these committees meet monthly to look at opportunities to improve safety and deal with any potential safety issues raised by employees. The work of these committees is then shared back to the larger Joint Health and Safety Committee and shared across the organization.

Alectra Utilities also has a robust site inspection program where leaders from all levels of the organization regularly perform site visits reviewing the site conditions, job planning documents, hazard identification, job set up and other safety factors with crews. These crew conversations are tracked in the company's Intelex system. The purpose of the visits is to have candid conversations around safety, to ensure lessons from other sites are shared, and to allow employees to provide feedback to the organization on their thoughts around safety. The information from these inspections is then also used to improve the overall Alectra Utilities safety program.

Alectra Utilities holds weekly Safety Starts and monthly Safety meetings with all Operations staff. The purpose of these meetings is to share safety information from across the organization for awareness and learning, to share relevant safety topics and to regularly review specific safety and operational procedures to ensure staff is compliant on all aspects of their safety performance. These meetings are also an opportunity for staff to share any safety thoughts and concerns with management so they can then be further actioned, tracked and shared across the organization.

Each one of these initiatives and programs is focused on ensuring Alectra Utilities staff are safe and have the opportunity to receive information and share information on a regular basis.

D Productivity and Continuous Improvement

D.1 Productivity

Since inception, within its work execution functions, Alectra Utilities has placed considerable emphasis on productivity and continuous improvement. Evidence of this can be found in the fact that although net capital investment has increased by 29% between 2020 and 2024, full-time equivalent (FTE) employees has not experienced such an increase (refer to *Exhibit 4, Tab 3 Workforce Staffing Plan & Strategy*). During this time (2020 to 2024), Alectra Utilities has implemented several changes to enhance productivity, including harmonization of work practices, process improvement and outsourcing of some maintenance tasks, as detailed below and in *Exhibit 1, Tab 6, Schedule 5 Productivity*, that have allowed it to deliver this increasing net capital investment efficiently. This emphasis on efficiency, productivity, and continuous improvement will be sustained throughout the 2027-2031 period as evidenced by the fact that although net capital investment is planned to increase by more than two times through to 2031 (from 2024 levels), internal FTEs are only planned to increase by approximately one quarter – a small fraction relative to the overall growth required in system investment.

At Alectra Utilities, productivity is achieved through tangible and direct actions such as the standardization of work practices, automation of processes, the utilization of digital field devices, and sophisticated management systems as detailed in *Exhibit 1, Tab 6, Schedule 5 Productivity*. The following bullets provide additional, specific examples.

- **Standardization and harmonization of construction standards, associated materials and equipment (as noted about under Work Enablers), and work practices.** Alectra Utilities has harmonized across various legacy regions. By completing work in a similar manner in each region, Alectra Utilities has minimized the number of unique materials, tools, vehicles and other equipment employed, delivered training and apprenticeships more efficiently and improve the mobility of internal and external resources. The harmonization journey has been ongoing for a number of years and is expected to be substantially completed by the end of the 2027-2031 period.
- **Standardization of resource selection by work type utilized by PDG.** By grouping and issuing work to internal or external resources by type (e.g. issuing rear lot construction and voltage conversion to external resources), coordinators can have better visibility into external resource schedules and availability, reduce the number of stakeholders being managed and ensure consistent and efficient resource scheduling across all regions. This also supports the standardization of tools, vehicles, training and work methods noted above by focusing resources where they are best equipped to complete the work efficiently and safely.
- **Adoption of business intelligence, artificial intelligence and automation.** Alectra Utilities has been increasingly working with BI software such as PowerBI to bring together project data from various enterprise data systems. This has allowed for previously manually produced reports (which were labour intensive and carried higher potential for human error) to be automated and in many cases delivered to stakeholders autonomously providing near real-time insights into cost data, program schedules, attainments and issues. By automating data entry, reducing data transposition between systems and focusing on insights, coordinators and their stakeholders have been able to focus on managing more

value driven work. This type of development is an ongoing process and will continue to provide productivity improvements during the 2027-2031 period.

- **Adoption of field devices.** Alectra Utilities has been increasing the number of field devices used by Lines resources. These devices allow crews to perform a variety of tasks from the field, including time entry, material requisitioning, completion of tailboards, accessing maps and project documents, redlining drawings and completing construction verification processes. As these devices continue to be implemented, resources will be able to perform increasing numbers of administrative tasks from the field, including the completion of service orders, retrieval and submittal of project documents, applying for and completing work protection, receiving and responding to new work and performing vehicle and asset inspections.
- **Barcoding System.** Alectra Utilities has integrated its barcoding system with its ERP platform, significantly enhancing the material issuance process by improving accuracy, traceability, and efficiency. This consolidation has led to better inventory management, reduced processing time, and fewer manual errors. By unifying capital work, material requirements, and supply scheduling within a single system, Alectra Utilities has improved operational effectiveness and cost efficiency while continuing to implement ERP enhancements that support productivity and inventory control.
- **Non-conformance Reporting.** Alectra Utilities introduced a Non-Conformance Reporting system through its GIS platform. This initiative streamlines the process of reporting discrepancies between electronic records and actual field conditions.

E Conclusion

In developing the 2027-2031 investment plan, Alectra Utilities carefully considered work execution factors and is confident in the ‘executability’ of the proposed plan. This confidence is rooted in the utility’s robust Capital Delivery Process, balanced approach to internal and external Labour Resources and robust systems in place for Work Enablers such as materials, fleet, outage scheduling and safety. Alectra Utilities’ overall Work Execution Strategy and mature systems have proven that they can scale up to deliver increasing levels of capital programs in an efficient and productive manner.

5.3.2 Overview of Assets Managed

5.3.2.1 Overview of Distribution Service Area

A Service Area and Customers

Alectra Utilities serves 17 municipalities, from the City of St. Catharines on the southwestern shore of Lake Ontario, to the town of Penetanguishene on the southeastern shores of Georgian Bay, and from the City of Guelph in the west to the City of Markham in the east, as shown in Figure 5.3.2 - 1. The service territory spans 1,912 square kilometers, approximately 99% of which is urban (1,896 sq km), with small rural areas comprising the remaining 1% (16 sq km).

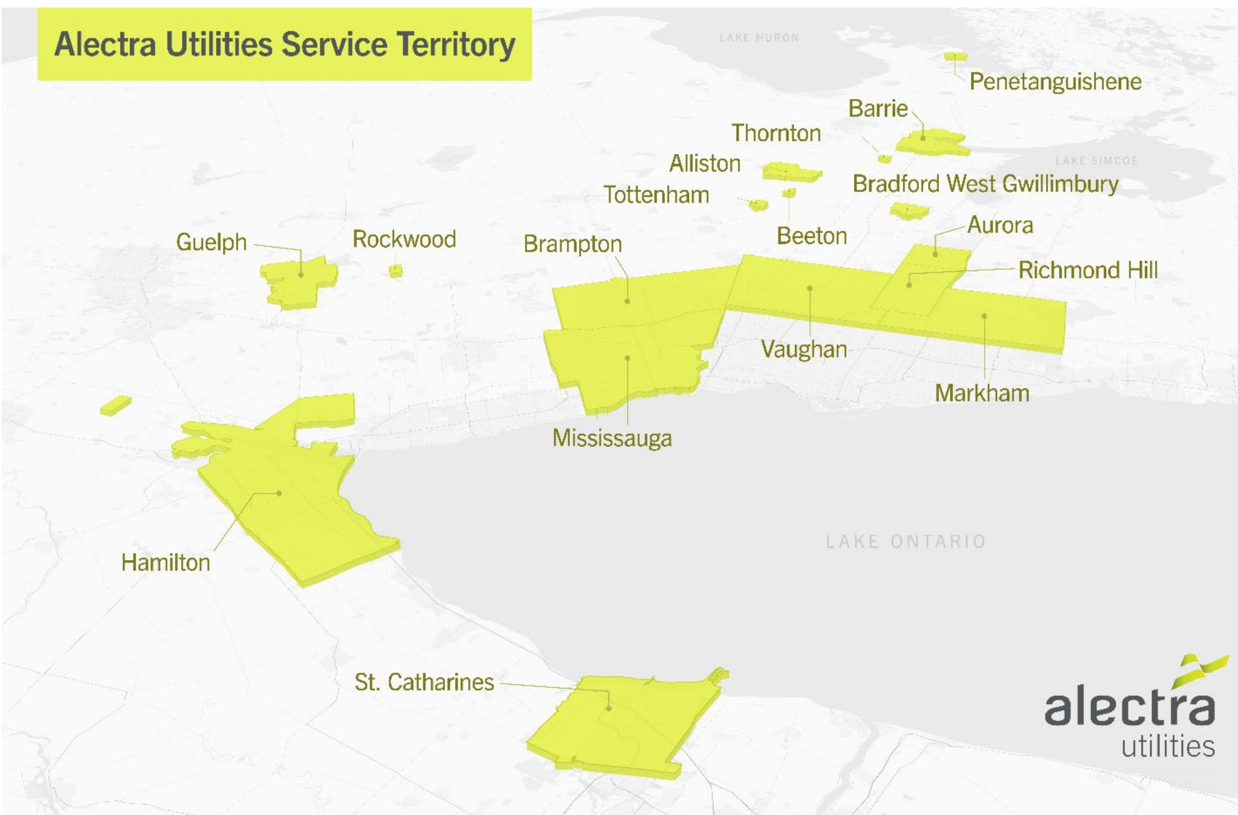

Figure 5.3.2 - 1 Alectra Utilities Service Territory

Based on customer count, Alectra Utilities is the second-largest electricity distributor in Ontario, supplying electricity to 1.1 million customers as of the end of 2024. The total annual energy consumption is approximately 27TWh. As presented in Table 5.3.2 - 1, the residential rate class represents around 90% of the customer base, while the General Service >= 50kW rate class accounts for approximately half of the total energy consumption. Detailed customer class, counts and consumption information is provided in Table 5.3.2 - 1.

Table 5.3.2 - 1 Customer Rate Class Account and Consumption

Rate Class	Customer Accounts (December 2024)	2024 Total Consumption (kWh)
Residential	988,866	8,358,536,700
General Service Less Than 50kW	89,126	2,812,814,202
General Service >= 50kW	12,530	13,195,860,346
Large User	36	2,847,681,212
Embedded Distributor(s)	1	2,924,406
Street Lighting Connections	241,236	93,691,395
Sentinel Lighting Connections	457	587,378
Unmetered Scattered Load Connections	11,398	47,635,914
Total	**1,343,650**	**27,359,731,553**

Alectra Utilities is embedded within Hydro One Network Inc.'s (HONI) distribution system at twenty stations. In addition, Alectra Utilities is a host distributor to HONI at one station. Total energy delivered to HONI's distribution system is tracked under a separate Embedded Distributor(s) rate class.

B Population Trends and Load Growth

B.1 Population Trends

Alectra Utilities forecasts a steady population growth in its service territory in the next two decades. The population is forecasted to grow by 23.6% from 2024 to 2041, for a 1.38% annual growth rate. This growth rate exceeds the provincial annual growth rate of 0.89%[58] in the same period by about 52%, representing a relatively higher number of future customer connections as compared to other LDCs. Table 5.3.2 - 2 summarizes the population growth forecast across the municipalities in Alectra Utilities' service area. The forecast indicates that there will be significant increases in population and the number of households in Simcoe, York, Guelph, Hamilton, Mississauga and Brampton. Based on the secondary municipal plans, the majority of the growth for Simcoe, York, Guelph and Brampton will be in the form of greenfield developments, while for Mississauga and Hamilton the majority of the growth will be in the form of intensification of the built-up areas. The sustained growth in population and the number of households will increase employment and other economic activities, such as increased connections in Industrial, Commercial, & Institutional (ICI) services. The peak demand is projected to increase due to the aforementioned growth.

[58] Ontario's population is projected to increase by 15.09 per cent, over 2.4 million, over the next 17 years, from an estimated 16.1 million on July 1, 2024, to over 18.5 million by January 1, 2041. Source: Ministry of Finance Ontario, https://www.ontario.ca/page/ontario-population-projections, accessed on September 29, 2025.

1 **Table 5.3.2 - 2 Population & Household Growth Forecast – 2021-2041**

City	Population						Households					
	2021	2026	2031	2036	2041	% Increase Population	2021	2026	2031	2036	2041	% Increase Households
Brampton	691,382	751,542	807,875	848,897	889,920	28.72%	247,826	264,478	280,723	295,336	309,950	25.07%
Mississauga	763,300	792,340	818,100	849,680	883,290	15.72%	249,514	262,450	279,850	298,940	317,840	27.38%
Hamilton	584,000	618,000	652,000	692,500	733,000	25.51%	222,540	240,320	258,100	276,635	295,170	32.64%
York	973,024	1,078,997	1,207,649	1,234,573	1,333,680	37.07%	311,657	351,392	394,004	436,977	478,958	53.68%
Guelph	147,000	157,500	168,000	177,000	186,000	26.53%	57,500	62,850	68,200	72,950	77,700	35.13%
Simcoe County	255,310	295,700	337,990	375,780	412,790	61.68%	88,140	104,750	120,790	137,260	153,770	74.46%
St. Catharines	137,886	142,993	148,099	155,982	163,865	18.84%	59,549	62,274	64,999	68,734	72,469	21.70%

Notes:	
1	**Brampton Population and Housing Data (2021-2041):** “Development Charges Background Study, The Regional Municipality of Peel, September 18, 2020, Watson Report”
2	**Mississauga Population and Housing Data (2021-2041):** “Development Charges Background Study, March 4, 2022, Hemson Report”
3	**Hamilton Population and Housing Data (2021-2041):** “City of Hamilton Land Needs Assessment to 2051, December 2020, Lorius Report”
4	**Guelph Population and Housing Data (2021-2041):** “Greater Golden Horseshoe: Growth Forecasts to 2051, August 26, 2020, Hemson Report”
5	York population and housing data (2021-2041):
	Markham:

	2021-2031: “2022 Development Charges Study, City of Markham, March 2022, Hemson Report”
	2031-2041: “2022 YORK REGION OFFICIAL PLAN Office Consolidation | June 2023, York Region Report”
	Richmond Hill:
	2021-2031: “Development Charges Background Study, Town of Richmond Hill, March 26, 2019, Watson Report”
	2031-2041: “Development Charges Background Study, City of Richmond Hill, December 22, 2023, Watson Report”
	Vaughan:
	2021-2031: “Development Charges Background Study, City of Vaughan, June 21, 2022, Hemson Report”
	2031-2041: “2022 York Region Official Plan Office Consolidation | June 2023, York Region Report”
	Aurora:
	2021-2031: “Development Charges Background Study, Town of Aurora, January 24, 2019, Watson Report”
	2031-2041: “2022 York Region Official Plan Office Consolidation | June 2023, York Region Report”
6	**St. Catharines Population and Housing Data (2021-2041):**
	"Development Charges Background Study, City of St. Catharines, June 2, 2021, Watson Report”
7	Simcoe County population and housing data (2021-2041):
	Barrie:
	“Greater Golden Horseshoe: Growth Forecasts to 2051, August 26, 2020, Hemson Report”
	Penetanguishene, Bradford, and New Tecumseth:
	“Growth Forecasts and Land Needs Assessment, March 31, 2022, Hemson Report”
8	York Region- Numbers indicated are for the Alectra Utilities service territory, including Markham, Vaughan, Richmond Hill, and Aurora.
9	Simcoe County –Numbers indicated are for the Alectra Utilities service territory, including Barrie, Bradford, New Tecumseth, and Penetanguishene.

B.2 Load Forecast (2024-2034)

Alectra Utilities service area is not contiguous; hence the distribution system is not seamlessly interconnected. Alectra Utilities service area is dispersed across a large area in Southern Ontario. To adequately reflect the dispersed nature of Alectra Utilities distribution system, Alectra closely monitors non-coincident system peaks (i.e. where maximum demand does not occur at the same time across all parts of the system) and follows a systematic approach to System Planning considering localized parameters for each region.

Figure 5.3.2 - 2 illustrates the 2024-2034 non-coincidental system peaks.

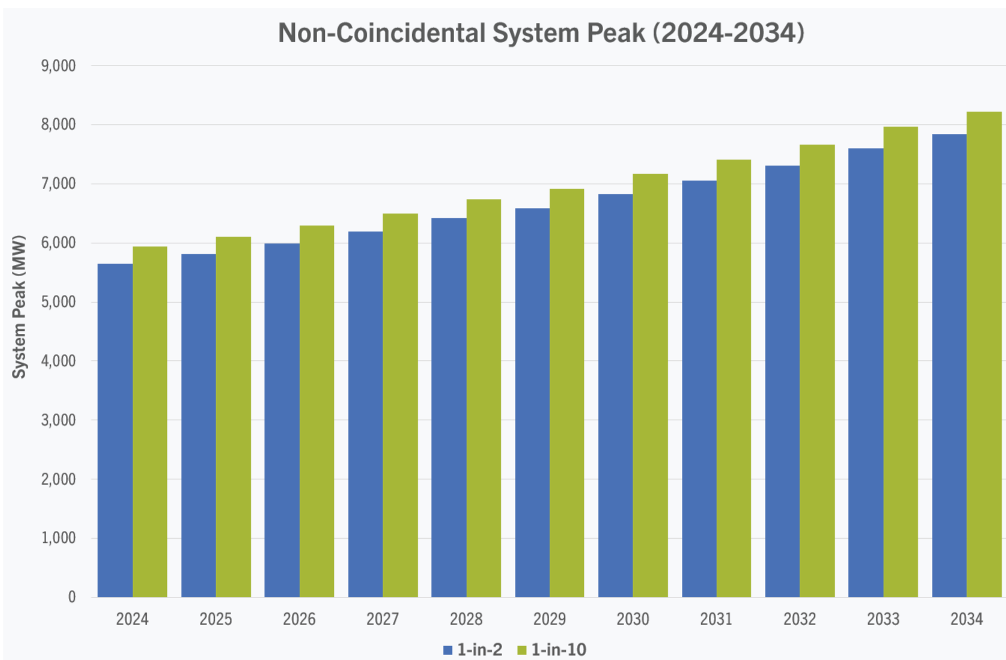

Figure 5.3.2 - 2 Non-Coincidental System Peak (2024-2034)

Alectra Utilities develops its future non-coincident summer peak demand forecasts under two weather scenarios: normal weather conditions (1-in-2)[59], and extreme weather conditions (1-in-10)[60].

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[59] 1-in-2 refers to a normal weather scenario, which has 50% probability of happening.

[60] 1-in-10 refer to a hot weather scenario, which has the probability of occurring 1 in 10 years. The system is planned to meet 1 in 10 weather conditions

Alectra Utilities has seen an increase in the following key areas which will impact the load forecast

- Organic Growth (New Homes and ICI Growth)
- Data Centre Expansion (Artificial Intelligence, Storage, Cloud Computing)
- Electrification of Transportation (Low Duty, Medium Duty and Heavy Duty Vehicles)

B.2.1 Organic Growth (New Homes and ICI Growth)

There are several Provincial initiatives such as "Places to Grow, Growth Plan for the Greater Golden Horseshoe" plans[61], Bill 162: The Get It Done Act, 2024[62] and the Bill 23: The More Homes Built Faster Act, 2022[63] which will lead to upward trend in construction of new homes and ICI growth to support the population growth.

Based on Alectra Utilities forecast an annual peak demand is expected to increase by 1.2% attributed to this organic growth.

B.2.2 Data Centre Expansion

One contributor to growth is the projected increased load pertaining to data centres in the Alectra Utilities service area. Load from data centres is approximately 115MW and Alectra Utilities has received applications and customer commitments to connect an additional 425MW of data centre load over the 2025-2031 period.

B.2.3 Electrification of Transportation

Alectra Utilities has seen CAGR of 50% (2021-2024) in adoption of EV vehicles in its service territory. Alectra Utilities projects more than 500,000 electric vehicles in its service area by 2031 (refer to the load forecast in *Appendix J - Alectra Load Forecast and System Capacity Adequacy Assessment Report)*.

C Climate Trends

Alectra Utilities operates a geographically broad and diverse distribution network, stretching from St. Catharines to Penetanguishene, and Guelph to Markham. This large and dispersed service

[61] https://www.ontario.ca/document/place-grow-growth-plan-greater-golden-horseshoe
[62] https://www.ola.org/en/legislative-business/bills/parliament-43/session-1/bill-162
[63] https://www.ola.org/en/legislative-business/bills/parliament-43/session-1/bill-23

area, exposed to a wide range of weather conditions, amplifies the challenges in managing climate impacts. As climate change drives more frequent and extreme weather events, Alectra Utilities' infrastructure faces increasing operational strain. Severe weather events not only contribute to long-term deterioration of assets but also have the potential to cause major outages and catastrophic equipment failures.

On July 31, 2025, the OEB released the Vulnerability Assessment and System Hardening Report Draft EB-2024-0199 (VASH) Project, providing recommendations to LDCs for integrating climate resiliency in their asset and investment planning. In lieu of upcoming OEB requirements and to support Alectra's efforts to incorporate climate assessments into its investment planning, Alectra Utilities has pursued a custom option by engaging a third-party expert to conduct a comprehensive climate vulnerability study that integrates climate projection data and the annual probability of various climate perils to inform region-specific climate risk profiles (discussed below). Additionally, Alectra Utilities has employed an asset-based approach through detailed structural resilience analysis of its overhead pole lines, detailed in *Section 5.3.2.3 C.1* below. The Value of Lost Load (VOLL) and the Project Cost and Benefit Analysis steps are integrated within the Copperleaf value framework as detailed in *Chapter 5.3.1 (Section 5.3.1.1).*

To better understand the impact of evolving weather patterns and severe climate events on its service area, Alectra Utilities engaged Hatch Ltd. in 2023 to conduct a comprehensive system vulnerability study, "Climate Risk and Vulnerability Assessment of the Alectra Utilities' Distribution System" (refer to *Appendix G - Climate Risk & Vulnerability Assessment*). This study assessed the vulnerability of Alectra Utilities' distribution infrastructure to various climate parameters by coupling the probability (likelihood) of occurrence with the severity (consequence) of their impact across the system. For reasons set out in the study, three climate scenarios from the Intergovernmental Panel on Climate Change (IPCC) Sixth Assessment Report (AR6), which are a combination of Shared Socio-economic Pathway (SSPs) and Representative Concentration Pathways (RCPs), were utilized as part of this assessment to capture a range of possible climate futures: SSP1-2.6, SSP2-4.5 and SSP5-8.5. These scenarios were integrated with projected climate data, in conjunction with Alectra Utilities' historical weather events and reliability data, to develop region-specific climate risk profiles. These risk profiles helped to identify areas most vulnerable to specific weather-related risks, for example flooding risks for underground assets due to anticipated rising precipitation levels in Hamilton, and increased wind gust events in Mississauga that impact distribution assets.

Table 5.3.2 - 3 provides a summary of the historical and projected average annual frequency of various climate parameters across all Alectra Utilities locations. The numbers in the parentheses represent the minimum and maximum frequency of a given climate parameter. The average annual frequency of several climate parameters, including high temperature, high wind gusts, precipitation and extreme weather events, is forecasted to be increasing. The most significant increase for the 2021-2075 period compared to historical data is expected for the wind gusts above 120KM/h, derechos, and tornadoes. The overall trend across the studied climate parameters indicates high-wind adverse events are increasing in both frequency and intensity in Alectra Utilities' service territory. As the intensity of adverse weather conditions escalates, the potential for more severe damage and longer recovery times grows, especially if assets are in deteriorated condition. Some parameters, such as ice storms, are forecasted to remain "stable". However, it should be noted that a stable frequency trend does not imply the event is infrequent or insignificant in its impact on the distribution network.

Table 5.3.2 - 3 Average Annual Frequency of Climate Parameters (Min, Max) - SSP2-4.5 Scenario

Climate Parameter	Unit (per year)	Baseline (1950-2020)	Study Period (2021-2075)	Trend in Frequency
Temperature > 32°C	Days	[5, 12]	[26, 37]	**Increasing**
Temperature > 40°C	Days	[0, 0]	[0, 1]	**Increasing**
Precipitation > 20mm	Days	[1, 1]	[1, 1]	Stable
Precipitation > 50mm	Days	[9, 11]	[10, 13]	**Increasing**
Wind Gust < 60KM/h	Hours	[347, 361]	[347, 361]	Stable
Wind Gust 61 to 80KM/h	Hours	[1, 16]	[1, 16]	Stable
Wind Gust 81 to 120KM/h	Hours	[0, 2]	[0, 2]	Stable
Wind Gust > 121KM/h	Hours	[7, 12]	[30, 37]	**Increasing**
Tornadoes	Events	1.5	2.8	**Increasing**
Derechos	Events	0.05 (1 in 20 years)	0.25 (1 in 4 years)	**Increasing**
Ice Storms	Events	0.34 (~1 in 3 years)	0.34 (~1 in 3 years)	Stable

The increased frequency and severity of severe weather require Alectra Utilities to strengthen system resiliency in response to the growing risk of damage to the system. In terms of extreme climate events, an emerging trend for Alectra Utilities' territories is the occurrence of widespread sustained windstorms, also known as derechos. Derechos are associated with rapidly moving thunderstorms that can result in significant infrastructure damage, with prolonged interruptions to the distribution system.

On May 21, 2022, a Derecho swept across Alectra Utilities' service territory with wind gusts of 120KM/h. The storm impacted one-third of all Alectra Utilities customers, resulting in over 100 poles being replaced reactively. Alectra Utilities required 12.5 hours to restore 90% of impacted customers, as entire pole lines required reactive rebuilding. The projections from Alectra Utilities climate vulnerability study indicate that the 2022 Derecho event is no longer considered an anomaly. Instead, events of this magnitude are now projected to occur approximately once every four years, as shown in Figure 5.3.2 - 3. This emerging trend presents a significant risk to the overhead distribution system.

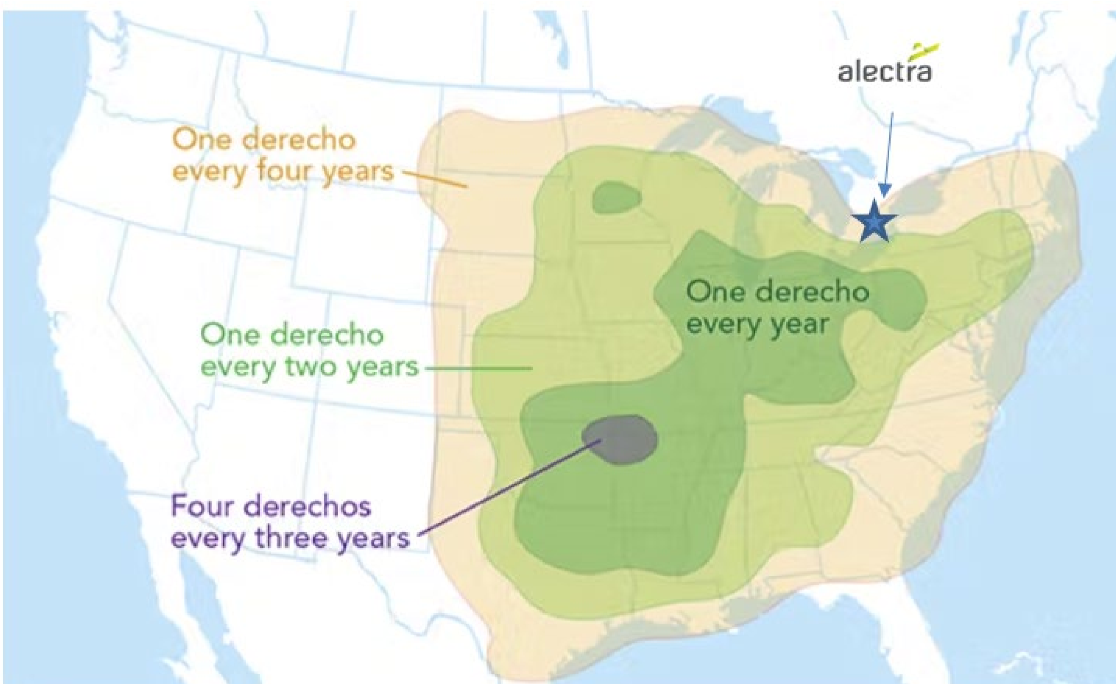

Figure 5.3.2 - 3 Derecho Event Occurrence Rate[64]

[64] https://www.tdworld.com/grid-innovations/distribution/article/20964810/storm-hardening-the-grid

These derecho events, characterized by their intense winds and widespread destruction, will increasingly challenge the resilience of the overhead distribution system. Alectra Utilities is required to proactively approach infrastructure planning and maintenance, ensuring that the system can withstand these increasingly likely extreme weather conditions. Moreover, the financial and operational impacts of these events cannot be understated, as detailed further in *Appendix B05 - Reactive Capital*. The cost of repairing and replacing damaged infrastructure, coupled with the potential for prolonged service interruptions, underscores the urgency of implementing robust mitigation strategies. By addressing these risks directly, Alectra Utilities can better safeguard its assets and ensure continued reliability and service continuity for its customers. Furthermore, from analyzing Alectra Utilities' historical sustained outage events, it was determined that higher wind gusts are consistently associated with a higher number of customers being interrupted.

Including the derecho event, Alectra Utilities experienced three MED events in 2022 caused by high winds with gusts of more than 100KM/h and impacting numerous sections of Alectra Utilities service areas. Alectra Utilities required more than ten hours to restore 90% of the customers impacted. Table 5.3.2 - 4 highlights the MED events Alectra Utilities has experienced from 2017 to 2024 caused by high winds and the associated Customer Interruptions (CI) and Customer Hours of Interruption (CHI).

Table 5.3.2 - 4 MEDs Associated with High Winds and Customer Impact

Event Date	Location	Wind Gust Rating	Customer Interruptions (CI)	Customer Hours of Interruptions (CHI)
1/11/2017	Brampton	101-120KM/h	3,779	11,794.78
3/8/2017	Hamilton and St. Catharines	101-120KM/h	29,386	59,843.29
4/7/2017	Simcoe County, Alliston	81-100KM/h	27,857	54,070.29
10/15/2017	Mississauga, and Vaughan	101-120KM/h	53,578	110,086.95
4/4/2018	Mississauga	81-100KM/h	13,408	18,429.27
4/14/2018	Hamilton and St. Catharines	81-100KM/h	15,745	38,486.50
4/15/2018	Mississauga	81-100KM/h	5,854	10,402.87
5/4/2018	All Alectra Territory	81-100KM/h	241,931	687,680.76
11/15/2020	Alectra East, Southwest and West	101-120KM/h	122,952	165,933.95
12/11/2021	All Alectra Territory	81-100KM/h	86,128	153,942.94
4/15/2022	Alectra East and West	Over 120KM/h	46,884	68,011.40
5/21/2022	All Alectra Territory	Over 120KM/h (Derecho event)	297,650	1,515,746.90
12/23/2022	All Alectra Territory	101-120KM/h	58,206	194,298.68

Climate projections from the system vulnerability study indicate that the majority of Alectra Utilities service territory will experience more of these high wind events, increasing in severity and intensity. Alectra Utilities must mitigate public safety risks, maintain system reliability, and account for customer preferences (refer to *Exhibit 1, Tab 5, Schedule 2 Application-Specific Customer Engagement*) to ensure that the distribution system is resilient to adverse environmental events. By investing in renewing overhead assets, tackling vulnerable areas, and investing in distributed automation, Alectra Utilities will be able to better protect its customers from increasingly more frequent and longer duration outages during major events. This proactive approach is expected to effectively mitigate the risk of service disruptions and system unreliability for customers during weather events.

Table 5.3.2 - 5, Table 5.3.2 - 6 and Table 5.3.2 - 7 illustrate the overall climate risk level results across different locations and climate parameters under historical (baseline) and future (study period) weather conditions. Risk levels are quantified by multiplying the probability of occurrence

of a given climate parameter (i.e. Temperature > 32°C) with the consequence of its impact on the affected area in the system (as measured by customers interrupted). The resulting risk ratings are classified as Very High, High, Moderate, Low, and Very Low. For more information on the risk assessment methodology, refer to *Appendix G - Climate Risk & Vulnerability Assessment.*

Comparing the risk profiles under baseline climate conditions presented with the projected climate conditions, the following observations are noted:

- High risks to Alectra Utilities' distribution system were identified for temperatures above 32°C, varying thresholds of wind gusts, high precipitation, and ice storms. These risks remain high in projected climate conditions.
- High wind conditions between 101-121KM/h have historically posed a Very High risk in Mississauga and Brampton, and this level of risk is projected to remain. Wind gusts exceeding 121KM/h in these areas are expected to increase in risk from Moderate to High.
- Derechos have historically posed a low risk but are now projected to pose higher risk in most areas, with Moderate risk expected in Penetanguishene and Tottenham-Beeton, and Very High Risk in Mississauga and Hamilton.
- Except for Aurora and Simcoe County, all areas will see a significant increase in risk level associated with temperatures greater than 40°C.

Table 5.3.2 - 5 Risk Heat Map Profile for Baseline (1950-2020)

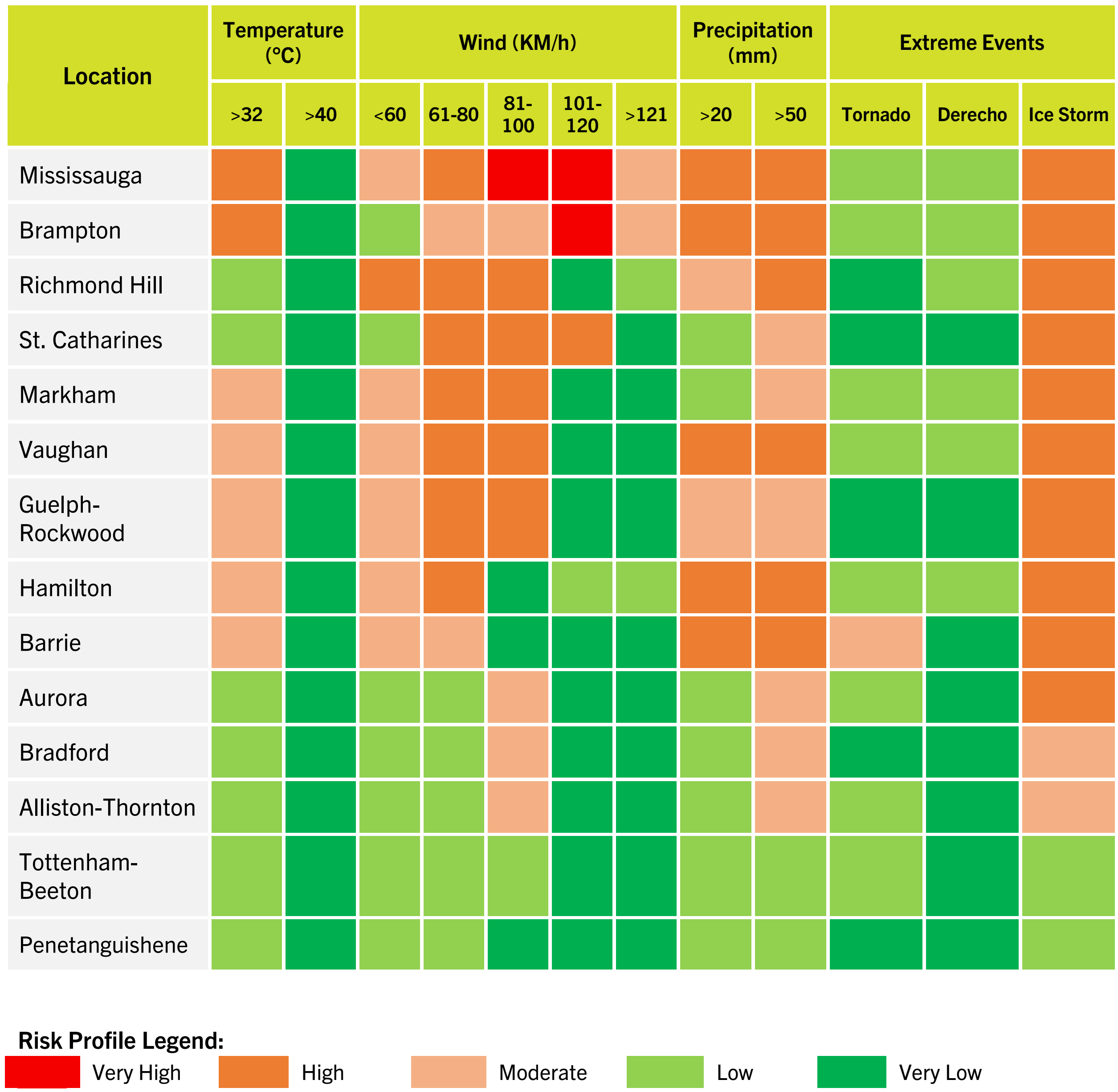

Table 5.3.2 - 6 Risk Heat Map Profile for Study Period (2021-2075)

Location	Temperature (°C)		Wind (KM/h)					Precipitation (mm)		Extreme Events		
	>32	>40	<60	61-80	81-100	101-120	>121	>20	>50	Tornado	Derecho	Ice Storm
Mississauga	High	High	Moderate	High	Very High	Very High	High	High	High	Moderate	Very High	High
Brampton	High	High	Low	Moderate	Moderate	Very High	High	High	High	Moderate	High	High
Richmond Hill	Low	Moderate	High	High	High	Very Low	Low	Moderate	High	Low	High	High
St. Catharines	Low	Moderate	Low	High	High	High	Very Low	Low	Moderate	Very Low	High	High
Markham	Moderate	Moderate	Moderate	High	High	Very Low	Very Low	Low	Moderate	Moderate	High	High
Vaughan	Moderate	High	Moderate	High	High	Very Low	Very Low	High	High	Moderate	High	High
Guelph-Rockwood	Moderate	High	Moderate	High	High	Very Low	Very Low	Moderate	Moderate	Very Low	High	High
Hamilton	Moderate	Moderate	Moderate	High	Very Low	Low	Low	High	Very High	Low	Very High	High
Barrie	Moderate	Moderate	Moderate	Moderate	Very Low	Very Low	Very Low	High	High	High	High	High
Aurora	Low	Low	Low	Low	Moderate	Very Low	Very Low	Low	Moderate	High	High	High
Bradford	Low	Low	Low	Low	Moderate	Very Low	Very Low	Low	Moderate	Low	High	Moderate
Alliston-Thornton	Low	Low	Low	Low	Moderate	Very Low	Very Low	Low	Moderate	Moderate	High	Moderate
Tottenham-Beeton	Low	Low	Low	Low	Low	Very Low	Very Low	Low	Low	Moderate	Moderate	Low
Penetanguishene	Low	Low	Low	Low	Very Low	Very Low	Very Low	Low	Low	Low	Moderate	Low

Risk Profile Legend:
Very High High Moderate Low Very Low

Alectra Utilities has incorporated locational and asset-level climate vulnerability assessments into its investment needs analyses to inform the Overhead Asset Renewal program, as detailed in *Appendix B01 - Overhead Asset Renewal*. More specifically, the pole renewal program has been further refined since the last DSP to enhance the identification and prioritization of poles at high risk of failure due to the increasing frequency and severity of extreme climate events.

The increased frequency and severity of severe weather require Alectra Utilities to strengthen system resiliency in response to the growing risk of damage to the system. Table 5.3.2 - 7 outlines Alectra Utilities' climate adaptation strategies and associated DSP investments for the 2027-2031 period in response to addressing the impact of evolving climate patterns. The system vulnerability study serves to underscore the importance of remaining vigilant in continuing and even increasing these initiatives further to sustain and improve system reliability.

Table 5.3.2 - 7 Climate Adaptation Strategies and Alectra's Response

Climate Adaptation Strategy	Alectra's Response
Enhancing grid flexibility and redundancy allows the grid to better withstand and quickly recover from disruptions. Adequate capacity (e.g. DER) allows for continued servicing when demand is high.	• Alectra Utilities is leveraging grid modernization technologies such as SCADA, distribution automation, DER Integration, non-wire alternatives, and protection and coordination devices as detailed in *Appendix B14 - Enabling Resiliency and Modernization*, to enhance grid flexibility and redundancy. Additional information on Non-Wire Solutions can be found in *Section 5.3.5 Non-Wires Solutions to Address System Needs.* • Alectra Utilities continues to upgrade infrastructure to provide higher line capacity to prevent system overload, safeguard power quality, and ensure rapid restoration in the events of outages as detailed in *Appendix B12 - Line Capacity*.
Upgrading to high-class poles and infrastructure can enhance system resilience. Alectra could benefit from changing design basis.	• *Appendix B01 - Overhead Asset Renewal outlines the replacement of pole assets that are deteriorated.* • Alectra Utilities engaged Hatch Ltd. to conduct a climate vulnerability study, presented in *Appendix G - Climate Risk & Vulnerability Assessment*, aiming to identify and address vulnerable assets due to impacts of climate change. More specifically, Alectra Utilities performed an asset-based approach, as discussed in Section C.1 below, to analyze poles' climate vulnerability.
Converting overhead lines to underground systems can significantly reduce their vulnerability to damage from ice storms and falling trees.	• As outlined in *Appendix B14 - Enabling Resiliency and Modernization*, Alectra Utilities has enhanced its focus on system hardening initiatives through rear-lot conversion projects, which target legacy systems and deteriorated assets that are increasingly susceptible to climate-related impacts. Rear-lot project planning involves the evaluation of multiple factors, with a preferred approach being the conversion of aging and deteriorated overhead systems into underground infrastructure.

Climate Adaptation Strategy	Alectra's Response
Enhanced vegetation management programs for power lines can prevent outages caused by vegetation contacting lines during high winds and storms.	• Alectra Utilities performs a comprehensive Vegetation Management Program on both a cycle-based and reactive basis which effectively maintains encroachments and removes infringing plant growth surrounding utility assets to ensure safety, reliability, customer satisfaction, and compliance with public policies. The program consists of two segments: Vegetation Management Cut Cycle and Reactive Tree Trimming. Refer to *Chapter 5.3.3 Asset Lifecycle Optimization Policies and Practices for* details on maintenance programs pertaining conductors and line hardware.
A more detailed assessment of structural resilience of strategic assets may be considered and the adaptation measures studied and prioritized.	• Alectra Utilities performs site inspections and testing. The ACA outlined in *Appendix E - Asset Condition Assessment* provides a list of assets classified as Very Poor and Poor which are regularly monitored and replaced as discussed in *Appendix B01 - Overhead Asset Renewal.* More specifically, Alectra Utilities performed an asset-based approach, as discussed in *Section C.1* below, to analyze poles' climate vulnerability.

C.1 Detailed Assessment of Structural Resilience of Overhead System

Deteriorated assets are more prone to damage by the increased stresses associated with adverse weather events. As climate change intensifies the frequency and severity of extreme weather conditions (i.e. high winds, tornadoes and derechos) means Alectra Utilities must take meaningful steps to reduce the number of deteriorated poles and associated overhead infrastructure. This is essential to mitigating risks to public safety, preventing prolonged outages and costly emergency repairs. One consequence of adverse weather events is the replacement of fallen poles, which is a complex and time-intensive process. This task requires crew members to safely remove debris and install new poles and wiring. The challenge is intensified during severe weather conditions, and the weather itself may pose safety risks for the workers. Structurally compromised or overloaded poles are particularly vulnerable to failure during high-wind conditions.

Leveraging the findings of the climate vulnerability study, Alectra Utilities performed an asset-based approach to analyze the wood and concrete poles' climate vulnerability. The analysis identified 29,092 existing poles vulnerable to climate-related stresses. Of that total, 4,387 are classified as high-risk, ‘structurally-overloaded’ poles, as they do not meet pole loading criteria and lack sufficient strength to withstand their specific climate loading scenarios. A subset of these vulnerable poles is considered for replacement as part of the Pole Renewal investment, as detailed in *Chapter 5.3.3 (Section 5.3.3.3) and Appendix B01 - Overhead Asset Renewal*. Both climate-vulnerability status, and the locational wind severity risk (informed by the climate vulnerability study) are used to further prioritize replacement deteriorated poles.

To identify these high-risk poles, Alectra Utilities utilized specialized pole loading software to evaluate the loading capacity of typical pole configurations. This evaluation factored in pole height, class, the number of primary conductors, as well as the presence of single-phase or three-phase transformers and load-interrupting switches. Any configuration that failed the loading capacity criteria was used as a ‘failure’ threshold. The resulting thresholds were then applied to pole demographics records obtained from Alectra Utilities’ Geographical Information System (GIS) to systematically identify climate-vulnerable poles. Ultimately, this resulted in identifying 4,387 high-risk climate-vulnerable poles that will be reviewed by Alectra Utilities staff and considered for replacement in conjunction with other prioritization factors (refer to *Chapter 5.3.3 Asset Lifecycle Optimization Policies and Practices* for further details).

As an example, Figure 5.3.2 - 4 illustrates the location of climate-vulnerable poles (not just the high risk) in Mississauga, Brampton, and St. Catharines. According to the climate vulnerability study, Mississauga, Brampton, and St. Catharines carry the highest risk among the Alectra Utilities territories for damaging wind gusts.

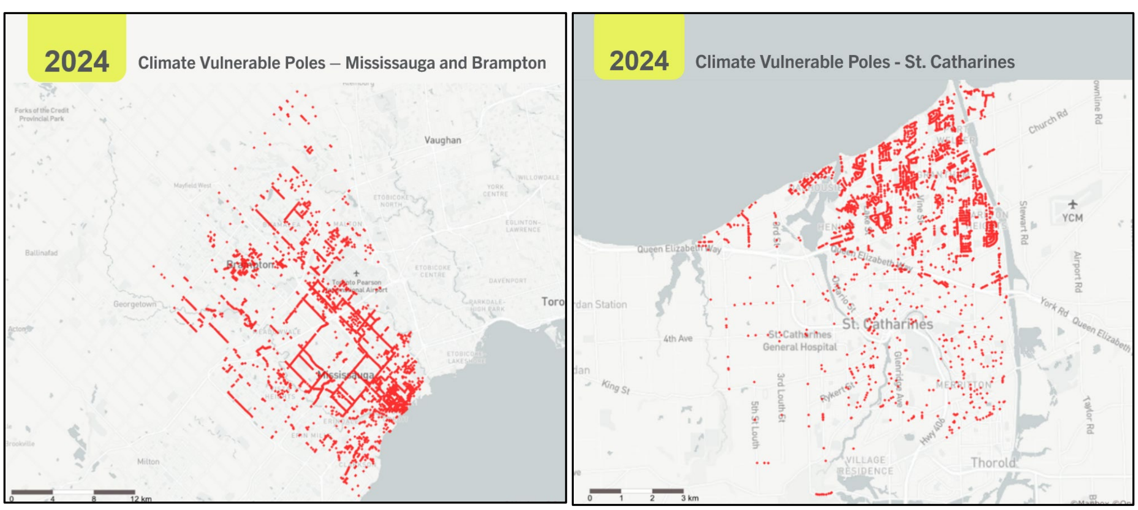

Figure 5.3.2 - 4 Climate Vulnerable Poles in Mississauga, Brampton and St. Catharines

The outcome of the climate study informing regional climate risk exposures, coupled with Alectra Utilities' detailed assessment of distribution poles, help to guide the development of targeted investments aimed at investing in areas and overhead assets identified as increasingly vulnerable to climate change. Alectra Utilities will continue to diligently monitor updates to the Intergovernmental Panel on Climate Change (IPCC) scenarios and adjust the climate models accordingly to ensure that the selected strategies remain robust and effective.

D Summary of System Configuration

Alectra Utilities' distribution system consists of stations infrastructure, and distribution infrastructure, including overhead and underground lines. The station infrastructure consists of 14 Alectra Utilities Owned Transformer Stations (TSs), and 68 HONI owned TSs which are connected to the 230/115kV provincial transmission grid. Each TS is a Dual Element Spot Network (DESN) station which consists of two transformers and two station buses with feeders exiting out from both. The transformers at each DESN are connected to a separate high voltage (HV) supply circuit through a motor-operated disconnect switch. Alectra Utilities owns and operates 149 Municipal Transformer Stations (MSs) that further stepdown voltage to 13.8kV, 8.32kV, or 4.16kV. The distribution infrastructure consists of a total of 1,371 feeders, 92 at 44kV, 300 at 27.6kV, 692 at 13.8kV, 19 at 8.32kV, and 268 at 4.16kV. As of December 2023, Alectra Utilities' total overhead conductor length is 18,464KM, and its total underground conductor length is 23,694KM.

Alectra Utilities service area is not contiguous and has been divided into four Operating Areas. The Operating Areas are further subdivided for planning purposes based on system configuration and topography.

The four Operating Areas and their Planning Zones are:

- Alectra East: two Planning Zones including York and Simcoe
- Alectra Central: two Planning Zones including Central North (Brampton) and Central South (Mississauga)
- Alectra West: one Planning Zone
- Alectra Southwest: one Planning Zone

These Operating Areas are shown below in Figure 5.3.2 - 5.

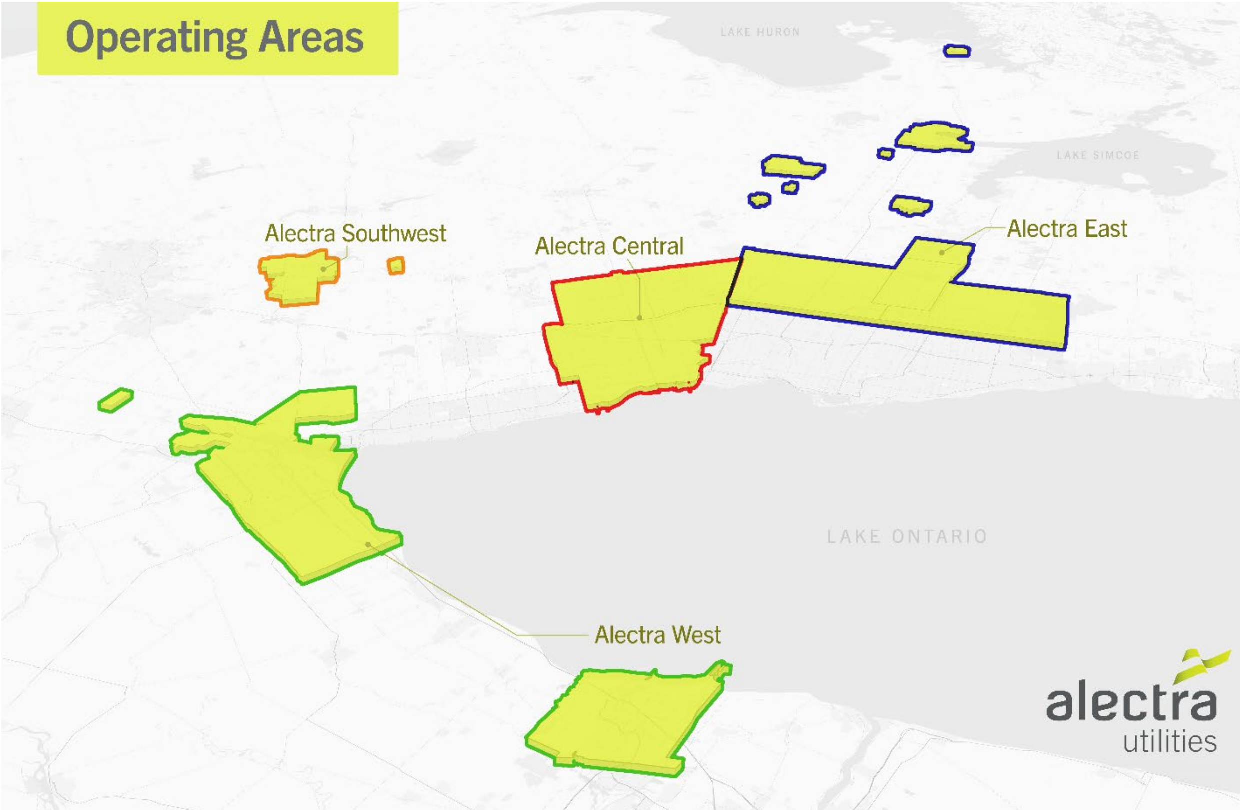

Figure 5.3.2 - 5 Alectra Utilities' Operating Areas

D.1 Alectra East

The Alectra East Operating Area is divided into two distinct Planning Zones: York and Simcoe.

D.1.1 York

York Planning Zone, shown in Figure 5.3.2 - 6, consists of two sub-planning zones: Southern York and Aurora. Southern York sub-planning zone includes Vaughan, Markham and Richmond Hill. Southern York sub-planning zone is supplied by 12 Alectra owned TSs and 9 HONI owned TSs. The majority of load is supplied at 27.6kV. A very small amount of load (approx. 0.5%) is supplied at 13.8kV or 8.32kV from 27.6/13.8kV or 27.6/8.32kV MSs in Vaughan and Markham. The 13.8kV and 8.32kV systems are in the form of isolated islands. As of 2025, there are two 27.6kV/13.8kV MSs and two 27.6/8.32kV MSs in Markham, and one 27.6/8.32kV MS in Vaughan.

Aurora is supplied by five 44kV feeders originating from HONI owned TSs in Newmarket, six 44/13.8kV MSs, and two 44/27.6kV MSs.

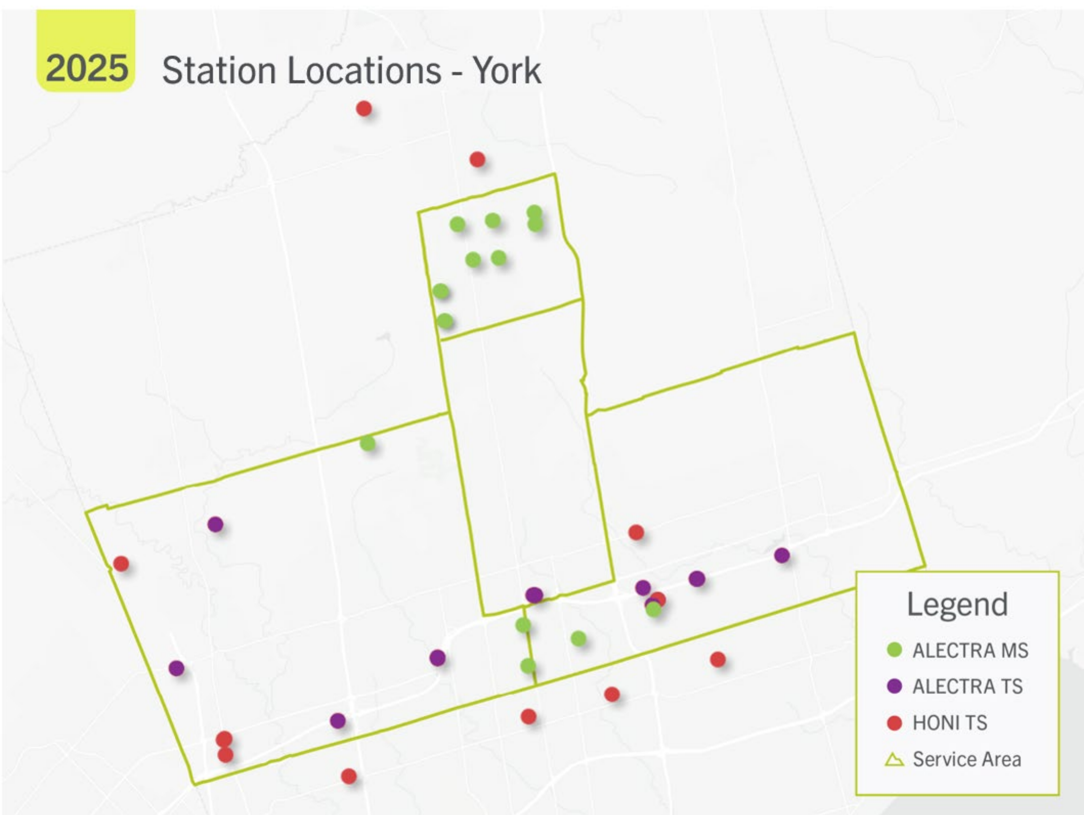

Figure 5.3.2 - 6 York Region Distribution System Overview

D.1.2 Simcoe

Simcoe Planning Zone is divided into five sub-planning zones as these areas are not contiguous: Barrie, Bradford, New Tecumseth (Alliston, Beeton, and Tottenham), Penetanguishene and Thornton.

D.1.2.1Barrie

Barrie is supplied by three HONI owned and operated TSs: Barrie TS, Midhurst T1/T2 and Midhurst T3/T4. Each transformer station consists of two transformers operating in parallel. Barrie is supplied by 17 44kV feeders from the HONI TSs: six from Barrie TS, four from Midhurst T1/T2, and seven from Midhurst T3/T4. These 44kV feeders service MSs and multiple customer-owned substations. The MSs transform the 44kV sub-transmission voltage to distribution voltages of 4.16kV and 13.8kV. There are 26 MSs in Barrie; ten 13.8kV MSs and 16 4.16kV MSs. Figure 5.3.2 - 7 shows the Barrie station locations.

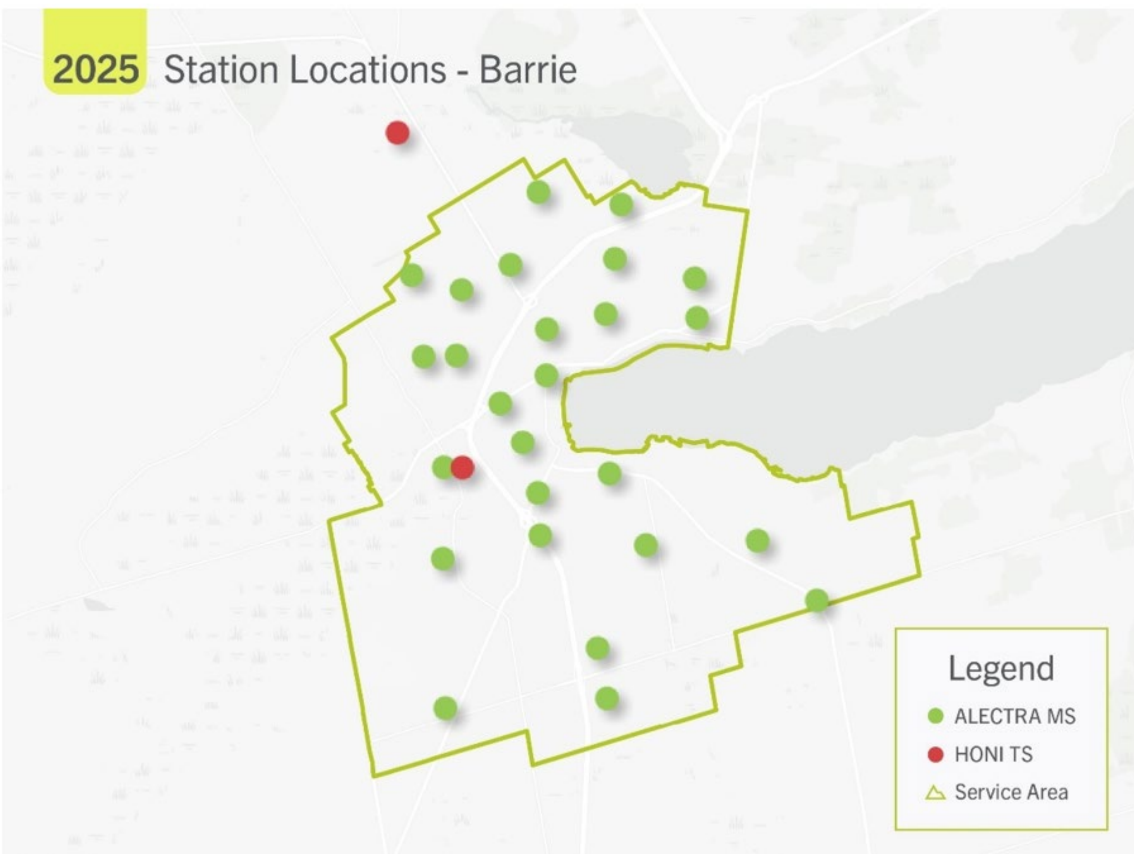

Figure 5.3.2 - 7 Barrie Station Locations

D.1.2.2Bradford

Bradford is supplied by 230/44kV Holland TS which is owned and operated by HONI. Bradford is currently supplied by three HONI owned 44kV feeders from Holland TS: 153M3, 153M4, and 153M10. These feeders also supply some HONI load outside of Alectra Utilities' service territory. These 44kV feeders service MSs and multiple customer-owned substations. The MSs transform the 44kV sub-transmission voltage to a distribution voltage of 13.8kV. There are four MSs in Bradford: MS321, MS322, MS323, and MS324 (refer to Figure 5.3.2 - 8).

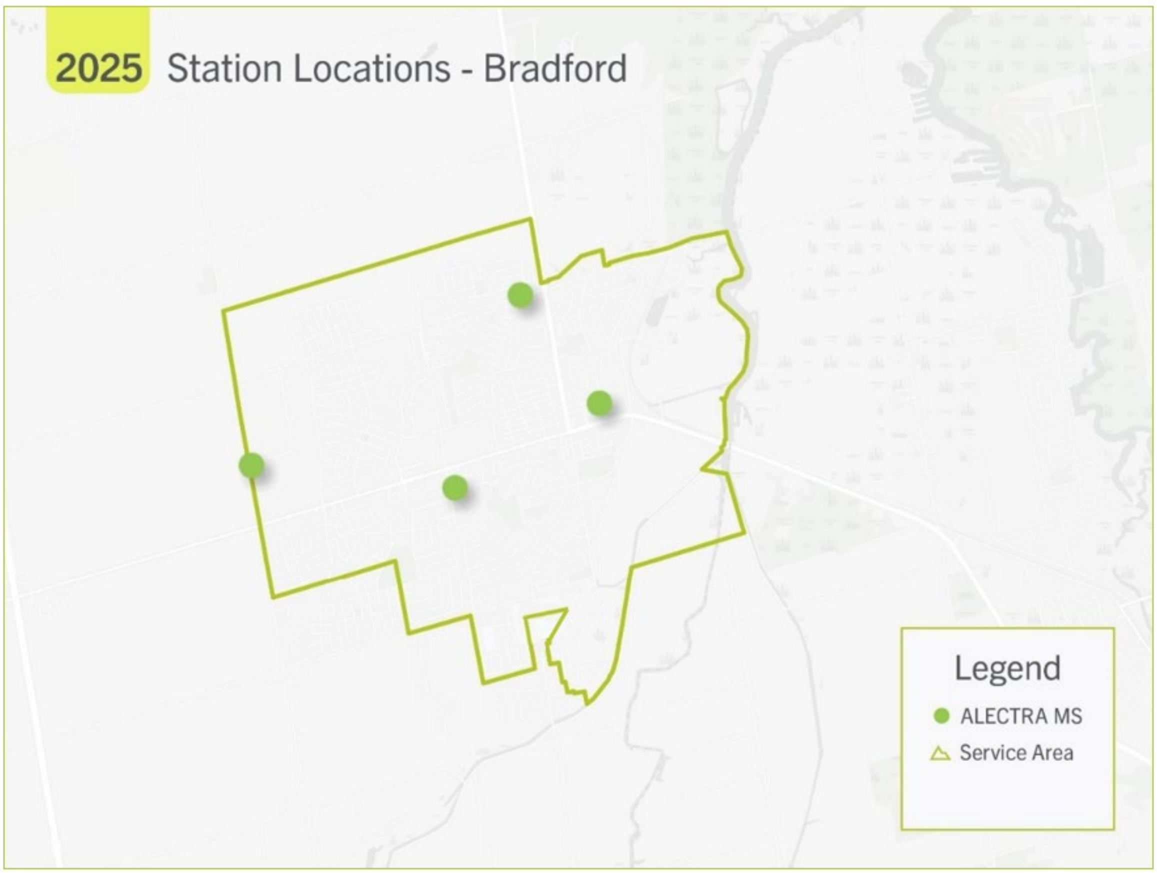

Figure 5.3.2 - 8 Bradford Station Locations

D.1.2.3New Tecumseth

New Tecumseth consists of three separate areas: Alliston, Beeton and Tottenham. Alectra Utilities plans each area independently because the distances between them preclude interconnection of distribution feeders.

All three areas are supplied by one HONI owned and operated transformer station: Everett TS. Three 44kV feeders are supplied from Everett TS: 138M6, 138M7, and 138M8. The 138M7 is dedicated to Alectra Utilities to supply load in Alliston, while the 138M6 is shared by Alectra Utilities and HONI to supply Alliston loads. The 138M8 is dedicated to Alectra Utilities to supply load in Beeton and Tottenham. These 44kV feeders service MSs and multiple customer-owned stations. The MSs transform the 44kV sub-transmission voltage to distribution voltages of 4.16kV, 8.32kV, and 13.8kV. There are four MSs in Alliston; three 13.8kV MSs and two 4.16kV MSs. There is a single 13.8kV MS in Beeton with two transformers on site. There are two 8.32kV MSs in Tottenham (refer to Figure 5.3.2 - 9, Figure 5.3.2 - 10, and Figure 5.3.2 - 11 for the station locations).

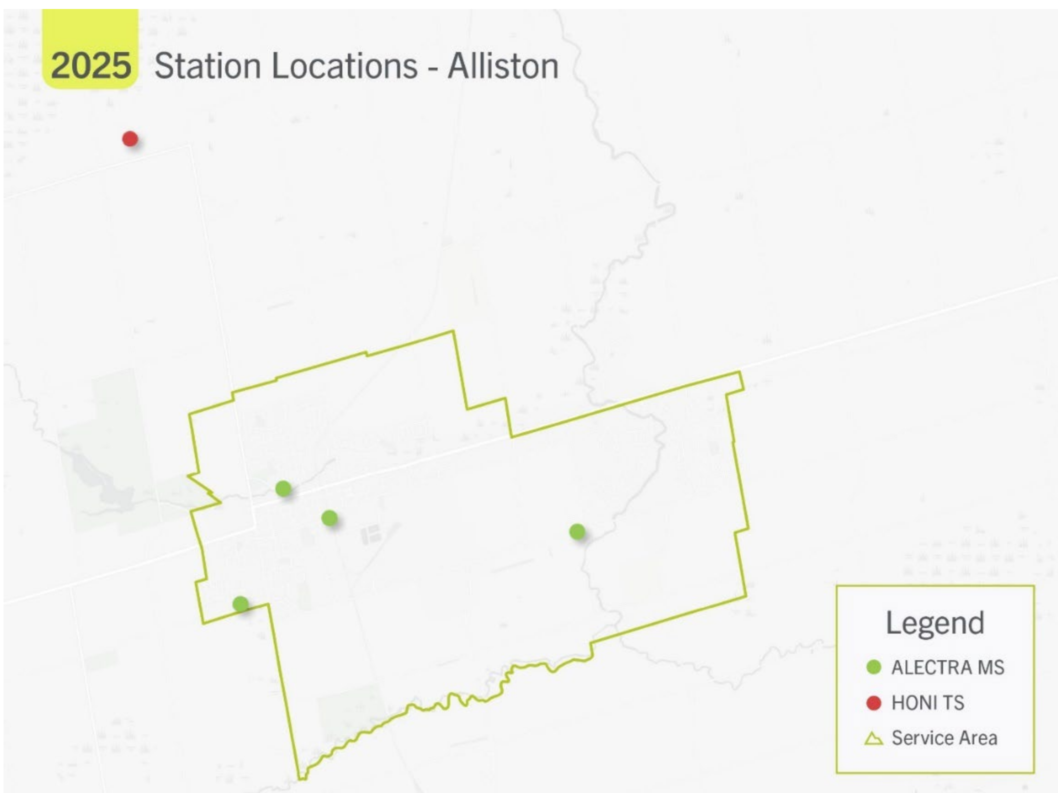

Figure 5.3.2 - 9 Alliston Station Locations

Figure 5.3.2 - 10 Beeton Station Locations

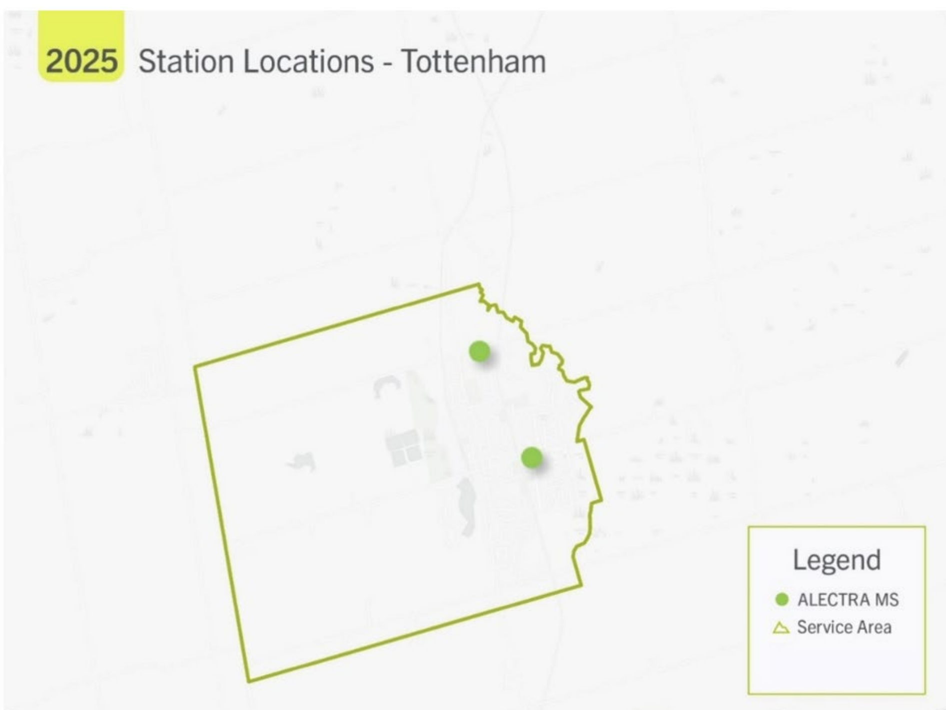

Figure 5.3.2 - 11 Tottenham Station Locations

D.1.2.4Penetanguishene

Penetanguishene is supplied by Waubaushene TS which is owned and operated by HONI through two 44kV feeders: 98M3 and 98M7. These 44kV feeders service MSs, multiple customer-owned stations. The MSs transform the 44kV sub-transmission voltage to a distribution voltage of 4.16kV. There are four MSs in Penetanguishene: MS421, MS422, MS423, and MS424.

44kV feeders also supply some HONI load outside of Alectra Utilities' service territory. HONI owned 8.32kV station in Penetanguishene supplies Alectra Utilities' load along Champlain Road with a single 8.32kV feeder (refer to Figure 5.3.2 - 12 for the station locations).

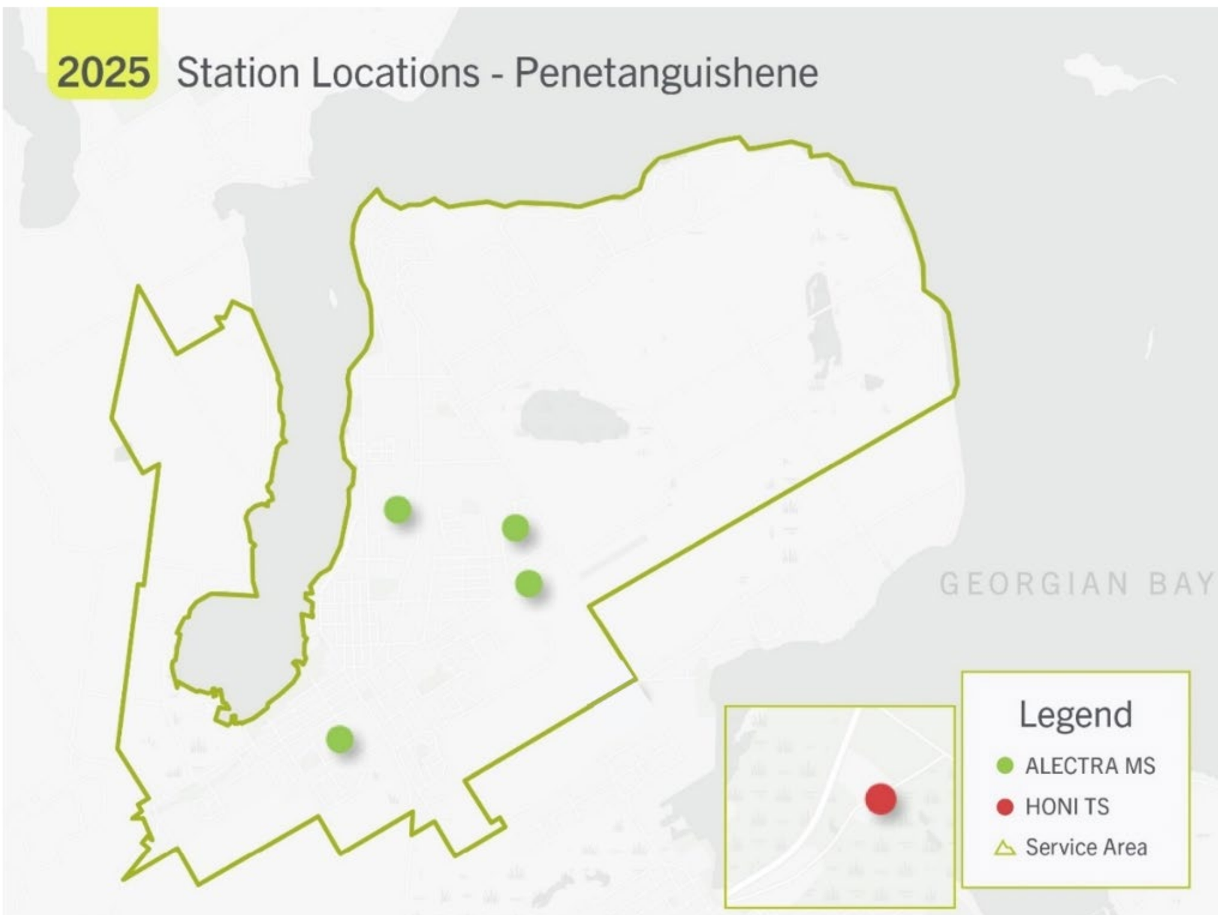

Figure 5.3.2 - 12 Penetanguishene Station Locations

D.1.2.5Thornton

Thornton is supplied by one 8.32kV feeder that is shared with HONI out of the HONI owned and operated Thornton DS, as shown in Figure 5.3.2 - 13.

Figure 5.3.2 - 13 Thornton Station Locations

D.2 Alectra Central

The Alectra Central Operating Area is divided into two Planning Zones: Central North (Brampton) and Central South (Mississauga).

D.2.1 Central North (Brampton)

Brampton is supplied by 11 transformer stations, including 10 HONI-owned and operated 230kV transformer stations (Goreway TS (three DESNs), Bramalea TS (three DESNs), Pleasant TS (three DESNs), and Woodbridge TS) and one Alectra-owned and operated 230kV transformer station (Jim Yarrow TS). The secondary voltages of the HONI-owned transformer stations are 44kV and 27.6kV and the Alectra station is 27.6kV. More details are illustrated in Figure 5.3.2 - 14.

In addition, further step-down from the 44kV and 27.6kV sub-transmission voltages is performed at nine MSs to primary distribution voltages of 13.8kV, 8.32kV and 4.16kV.

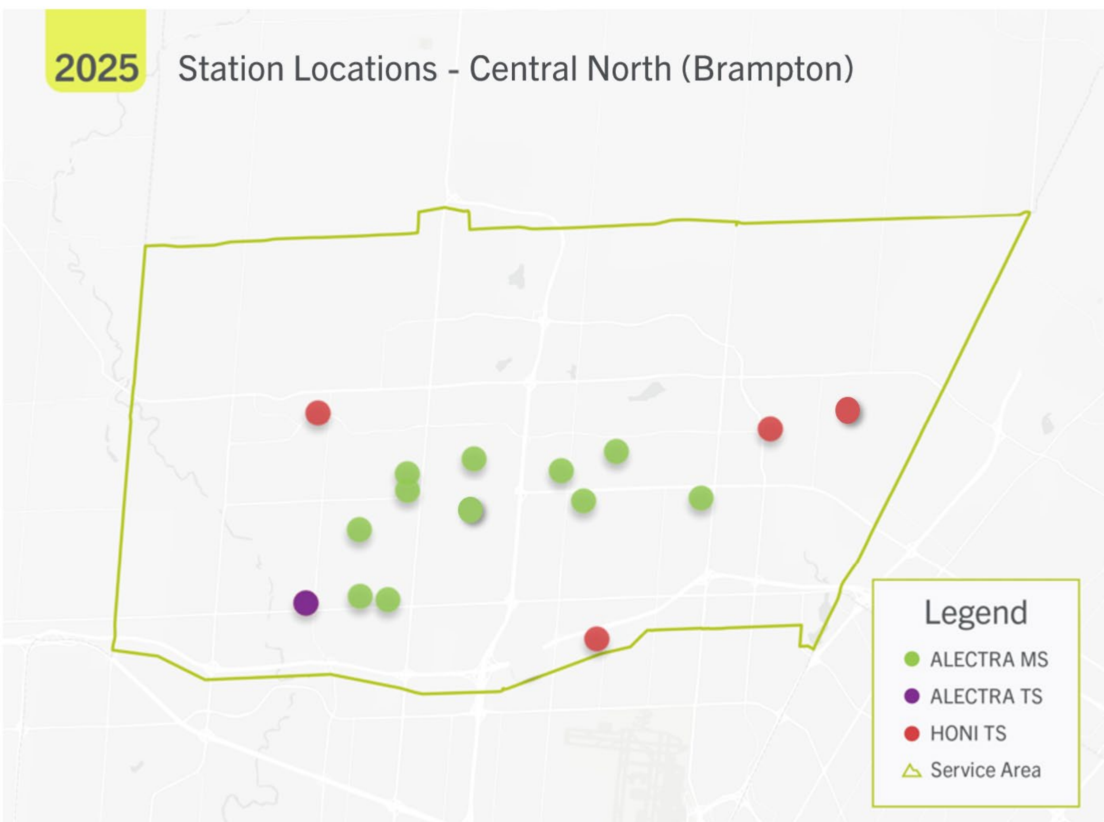

Figure 5.3.2 - 14 Central North (Brampton) Stations

D.2.2 Central South (Mississauga)

Mississauga is supplied by 16 TSs owned and operated by HONI, where the voltage is transformed from 230kV to either 44kV or 27.6kV. The HONI owned transformer stations are:

- Meadowvale TS
- Churchill Meadows TS
- Erindale TS (three DESNs)
- Tomken TS (two DESNs)
- Bramalea TS (two DESNs)
- Woodbridge TS
- Oakville TS
- Lorne Park TS
- Cooksville TS (two DESNs)
- Richview TS
- Cardiff TS

Mississauga's distribution system has voltages of 27.6/4.16kV, 44/13.8kV, and 27.6kV. More details are illustrated in Figure 5.3.2 - 15.

In addition, further step-down from the 44kV and 27.6kV sub-transmission voltages is performed at 67 MSs to primary distribution voltages of 13.8kV and 4.16kV.

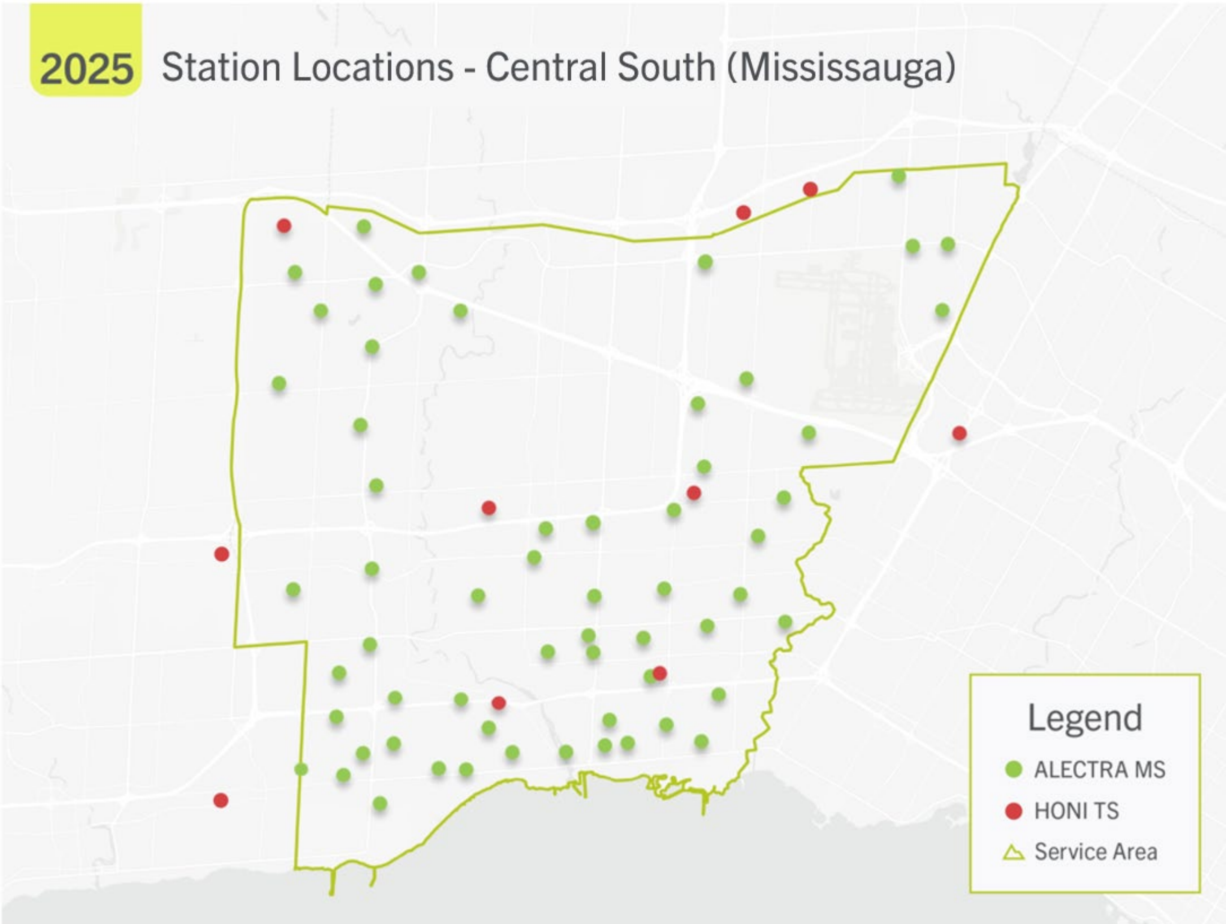

Figure 5.3.2 - 15 Central South (Mississauga) Stations

D.3 Alectra West

The Alectra West Operating Area contains one planning zone, which is further divided into two sub-planning zones: Hamilton and St. Catharines.

D.3.1 Hamilton

Hamilton is supplied by 19 TSs owned and operated by HONI. Each transformer station consists of at least two transformers operating in parallel, supplying one or more busses at 13.8kV or 27.6kV. These 13.8kV and 27.6kV feeders service MSs, and multiple customer-owned stations. The MSs transform the medium voltage feeders to distribution voltages of 4.16kV and 8.32kV.

There are 15 MSs in Hamilton. This number decreased from 23 MSs in 2019 as the Voltage Conversion projects proceed to remove the 4.16kV and 8.32kV systems. Figure 5.3.2 - 16 illustrates the stations in the map.

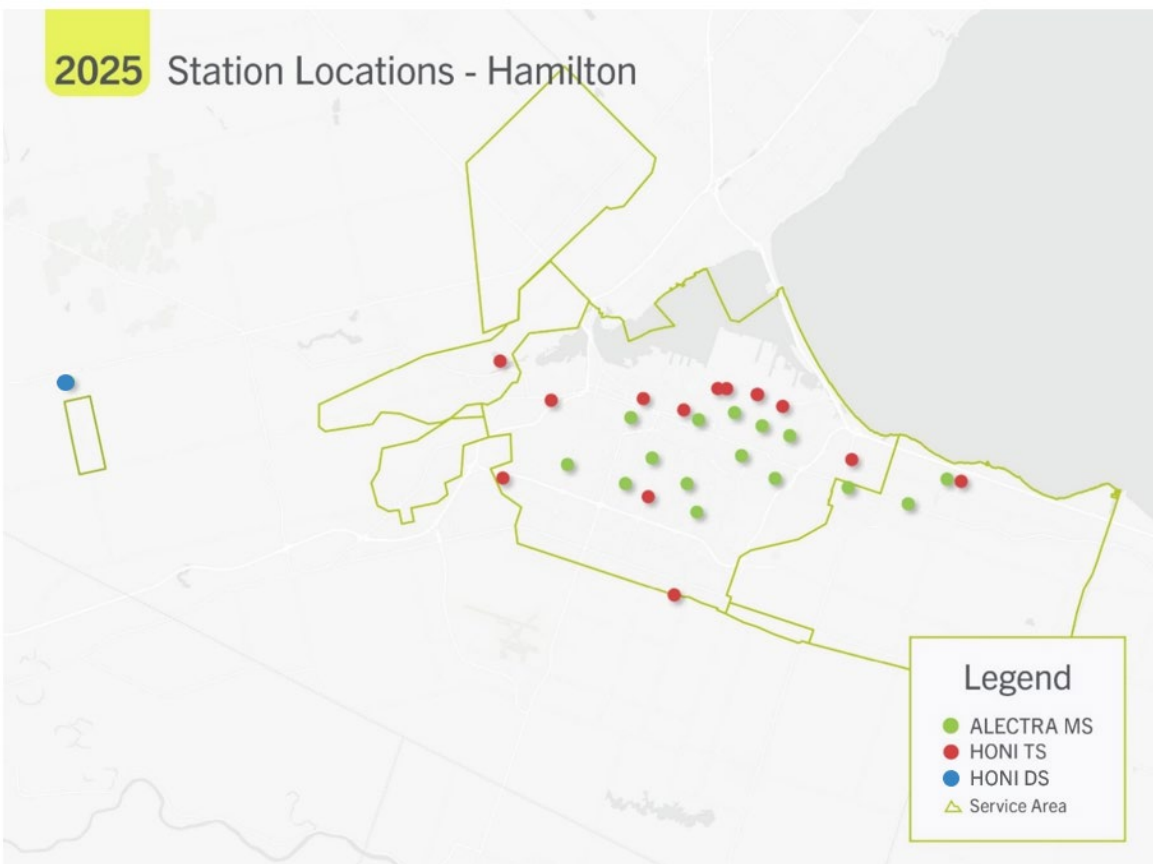

Figure 5.3.2 - 16 West (Hamilton) Stations

D.3.2 St. Catharines

St. Catharines is supplied by five HONI transformer stations: Bunting TS, Carlton TS, Glendale TS (2 DESNs) and Vansickle TS. Each TS supplies multiple 13.8kV busses via two or more transformers. From these busses multiple 13.8kV feeders make up the distribution network in St. Catharines. All the older 4.16kV stations have been converted to 13.8kV. Figure 5.3.2 - 17 illustrates station locations on the map.

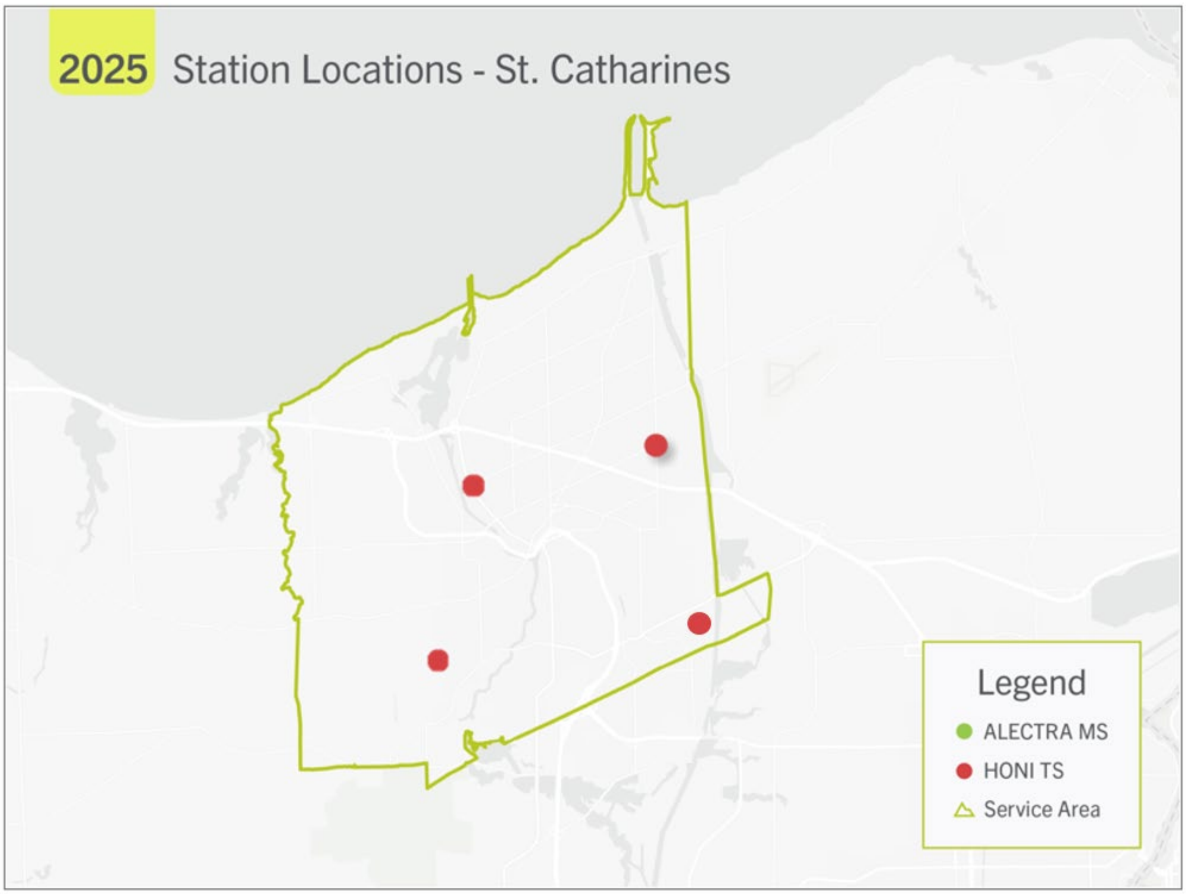

Figure 5.3.2 - 17 West (St. Catharines) Stations

D.4 Alectra Southwest

The Alectra Southwest Operating Area contains one planning zone, which is further divided into two sub-planning zones: Guelph and Rockwood.

The City of Guelph is supplied by five HONI TSs (Hanlon TS, Cedar TS (two DESNs), and Campbell TS (two DESNs) and one Alectra Utilities owned TS (Arlen TS). Cedar TS, Hanlon TS and Arlen TS step-down 115kV transmission supply to 13.8kV while Campbell TS steps-down 230kV transmission supply to 13.8kV for primary distribution feeders.

In the Village of Rockwood, supply is provided by two Alectra Utilities owned MSs (Rockwood MS1, Rockwood MS2). Both stations are supplied from 44kV feeders originating from HONI Fergus TS. Primary distribution feeders are operated at 8.32kV.

Figure 5.3.2 - 18 shows TS and MS locations in the region.

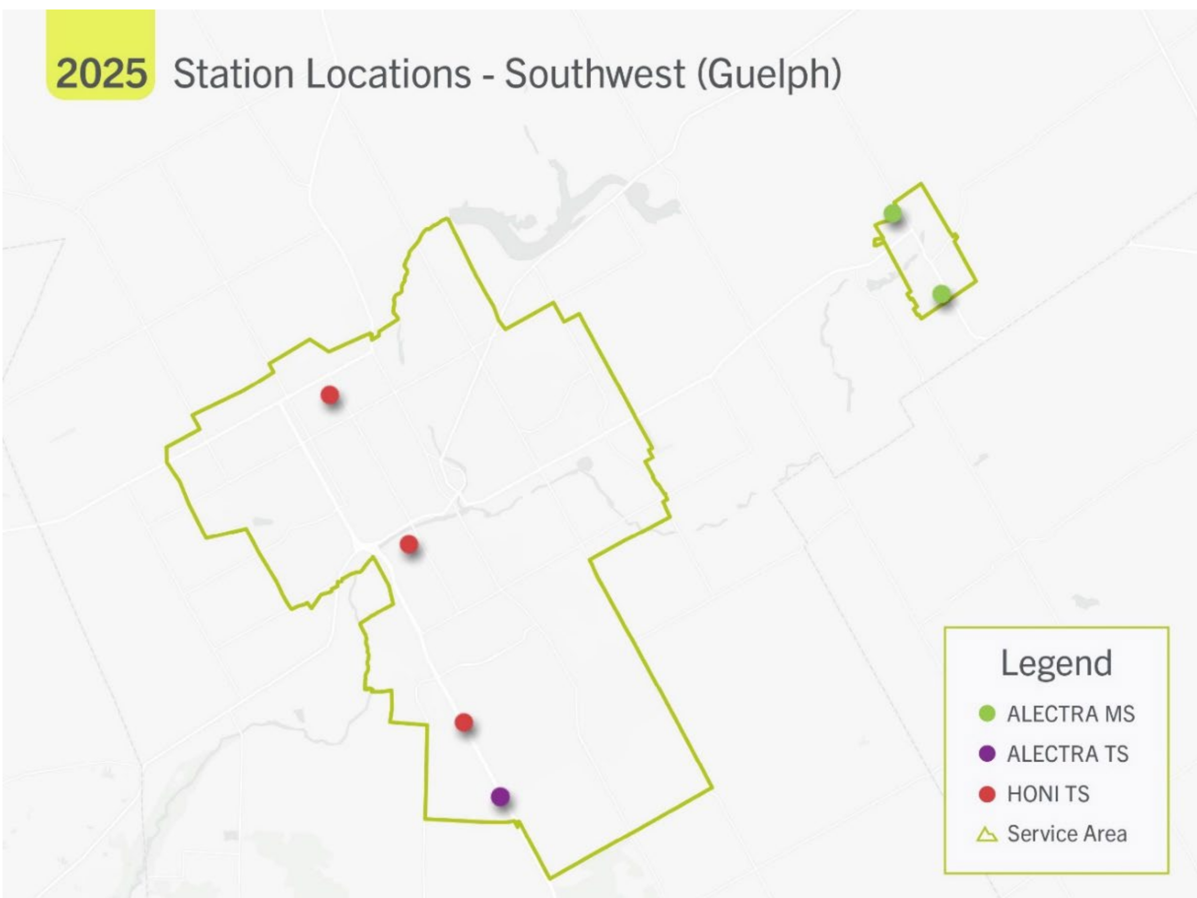

Figure 5.3.2 - 18 Southwest Station Locations

5.3.2.2 Asset Information

A Asset Inventory and Condition

Alectra Utilities conducted an asset condition assessment for its distribution assets, station assets pursuant to its Asset Management Planning Process detailed in *Chapter 5.3.1* (*Section 5.3.1.1).*

Kinectrics Inc. (Kinectrics) was retained to conduct an independent review of Alectra Utilities' Health Index (HI) methodology used for determining the condition of its assets and how Alectra Utilities' methodology compares with best industry practices. Kinectrics assurance review of the Asset Condition Assessment (ACA) HI methodology is provided in *Appendix F – Alectra 2024 Health Index Methodology Review*.

To support most cost-effective investment requirements, Alectra Utilities utilizes HI for determining the condition of individual assets. The HI results illustrate the condition for each major asset class across the HI spectrum and classify the health of its assets into one of five categories, from "Very Poor" to "Very Good", as described in Figure 5.3.2 - 19.

Health Index Categorization

Category	Criteria	Range
Very Good	Assets with no signs of deterioration.	HI ≥ 85%
Good	Assets in solid working condition with minimal signs of deterioration.	70% ≤ HI < 85%
Fair	Assets functional but showing clear signs of deterioration.	50% ≤ HI < 70%
Poor	Assets exhibiting significant degradation requiring attention.	25% ≤ HI < 50%
Very Poor	Assets showing major degradation or critical condition demanding urgent intervention.	HI < 25%

Figure 5.3.2 - 19 Health Index Categorization

Kinectrics concluded that input data and weights, test results interpretation, inspection records analysis and scoring criteria of the HI formulae used by Alectra Utilities were well aligned with the best industry practices and represent a sound methodology for assessing the condition of individual assets. Following the detailed review of Alectra's HI methodology for station and distribution assets, Kinectrics determined that the HI methodology used is aligned well with best industry practices and in the case of station power transformers and circuit breakers/reclosers, represents the industry's leading edge in HI modelling. Given the high quality of the HI methodology, the ACA results should be highly credible. [1]

Alectra Utilities illustrates the 2023 asset inventory, age distribution, and HI results for distribution assets and station assets in *Section 5.3.2.2 A.1* and *Section 5.3.2.2 A.2*, respectively. The age distribution illustrates the Typical Useful Life (TUL) and End of Useful Life (EUL). The TUL represents the expected typical operational lifespan before planned intervention (i.e. replacement or refurbishment) is required, while EUL represents the age where the asset is expected to have lost the ability to perform as designed. Further details on TUL, EUL, and HI calculation for each asset class are provided in *Appendix E - 2023 Asset Condition Assessment.*

[1] As per *Appendix F – Alectra 2024 Health Index Methodology Review*, Page 1, 3 and 5.

Figure 5.3.2 - 20 illustrates the HI results from the 2023 ACA for distribution and station assets.

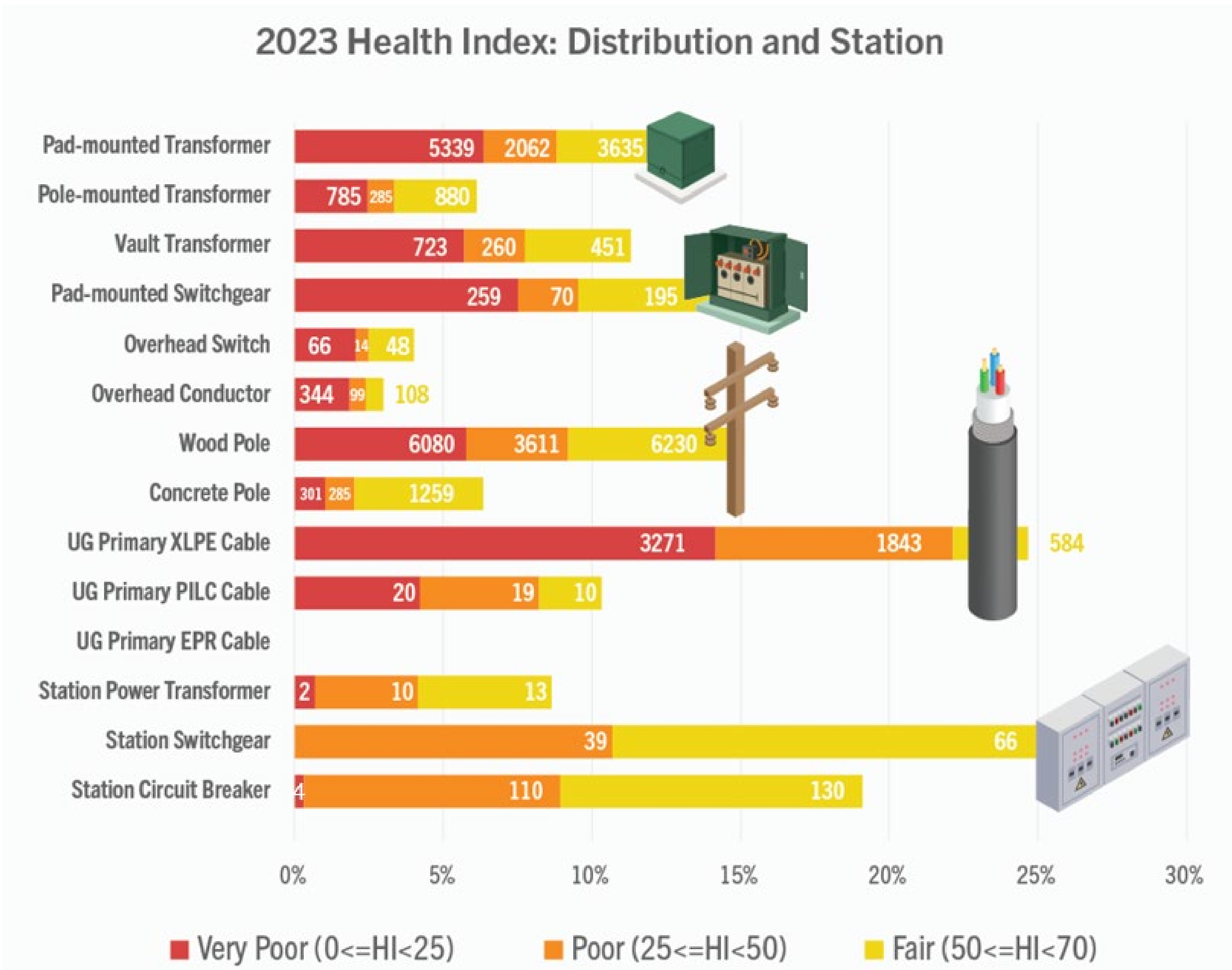

Figure 5.3.2 - 20 Health Index by Asset Class

Figure 5.3.2 - 21 illustrates the proportional increase in deteriorated distribution assets. Since 2018, deterioration across all major asset classes has increased by 49%. A deteriorated asset is defined to be in “Poor” or “Very Poor” condition in the ACA. Deteriorated assets exhibit significant degradation or demand urgent intervention to mitigate public safety, environmental, and reliability risks.

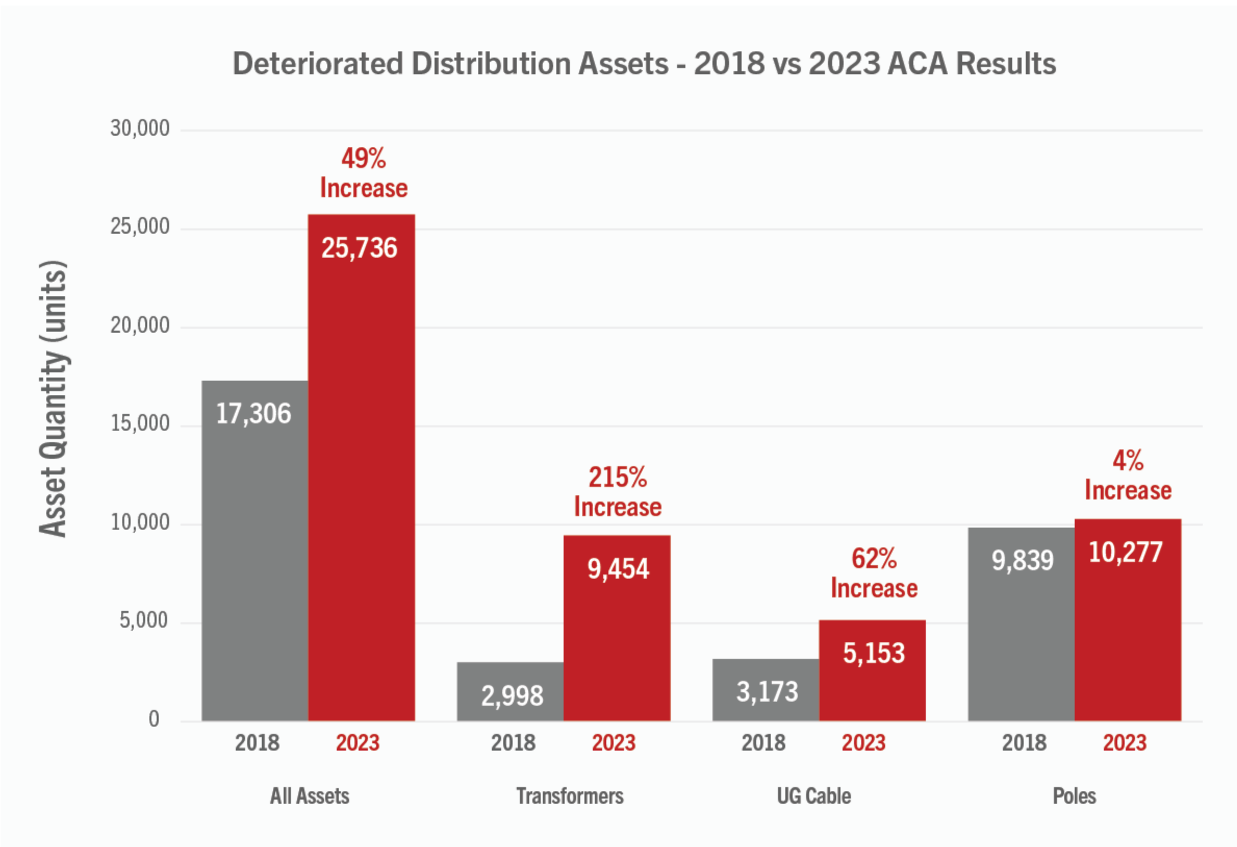

Figure 5.3.2 - 21 Deteriorated Distribution Assets (2018 vs. 2023)

The asset inventory for metering is summarized in *Section 5.3.2.2 A.3* and further detailed in *Appendix B06 - Network Metering*.

Asset inventory for facilities and fleet is summarized in *Section 5.3.2.2 A.4* and further detailed in *Appendix B07 - Facilities Management* and *Appendix B08 - Fleet Renewal*.

Section 5.3.2.2 A.1 to *Section 5.3.2.2 A.4* provides an overview of asset information, including asset inventory for distribution assets, station assets, metering assets, and facilities and fleet. In addition, failure modes and impacts are provided for distribution and station assets.

A.1 Distribution Assets

Table 5.3.2 - 8 summarizes the inventory of distribution assets by Operating Area.

Table 5.3.2 - 8 Asset Inventory (Distribution Assets)

Asset Category	Operating Area				
	Central	East	West	Southwest	Total
Pad-mounted Transformers	32,640	39,130	7,860	4,255	83,885
Pole-mounted Transformers	7,914	8,284	13,757	1,852	31,807
Vault Transformers	5,198	3,772	3,587	113	12,670
Switchgear	1,130	1,885	323	106	3,444
Overhead Switches	994	1,128	649	421	3,192
Overhead Conductors (length[2], KM)	7,142	6,876	3,369	1,076	18,463
Wood Poles	19,253	35,655	40,019	10,335	105,262
Concrete Poles	14,895	2,322	11,048	845	29,110
UG Primary XLPE Cables[3] (length, KM)	10,262	8,979	2,681	1,185	23,106
UG Primary PILC Cables[4] (length, KM)	1	0	473	0	474
UG Primary EPR Cables[5] (length, KM)	0	0	114	0	114

[2] Length is applicable to overhead conductor and underground cable and represents total length, not circuit length
[3] Underground primary cross-linked polyethylene cables
[4] Underground primary paper-insulated lead-covered cables
[5] Underground primary ethylene-propylene rubber cable

Table 5.3.2 - 9 lists typical failure modes and impacts for each distribution asset considered in the ACA.

Table 5.3.2 - 9 Typical Asset Failure Modes and Impacts (Distribution Assets)

Asset	Typical Failure Modes	Impacts
Distribution-Class Pad-Mounted, Pole-Mounted and Vault Transformers	• Internal faults • Major corrosion exposing live components within the enclosure • Leaking oil • Overloading • Moisture and flooding	• Compromised enclosure posing risk of damaged or contaminated internal components and risk of public safety causing injury • Environmental contamination and remediation due to oil spill • Stressed components and insulation damage • Declining accessibility and condition of confined space and components within
Pad-Mounted Switchgear	• Major corrosion exposing live components within the enclosure • Leaking oil • Leaking sulfur hexafluoride (SF_6) gas • Internal component damage (e.g. insulation) and contamination	• Compromised enclosure posing risk of damaged or contaminated internal components and risk of public safety causing injury • Environmental contamination and remediation due to oil spills and pollution ○ Pollution: SF6 has an equivalent effect of 23,500 times that of carbon dioxide (CO2) • Tracking and flashovers lead to a prolonged outage and public safety risk
Overhead Load Interrupter Switches (LIS)	• Burnt or melted contacts and flashover • Corrosion and seized levers	• Potential pole fire posing public safety and reliability risk • Inoperability leading to prolonged restoration and switching
Overhead Primary Conductors	• Conductor breakage due to overheating, or galvanic corrosion • Tree and animal contacts	• Under-sized conductor falling to the ground posing a significant public safety risk • Customer interruptions and potential fallen trees posing risk of prolonged restoration
Wood and Concrete Poles	• Rot and decay (ground line or pole top) • Large cracks, spalling, and exposed rebar • Insect and animal infestation (e.g. woodpeckers, carpenter bees, etc.)	• Loss of pole structure integrity and remaining strength • Pole attachments become insecure and collapse • Pole fires due to tracking and contamination • Poles unable to withstand wind gusts with potential to fall to the ground posing significant safety risks

Asset	Typical Failure Modes	Impacts
	• Mechanical damage (e.g. vehicles and snowplows) • Porcelain and first-generation polymer insulators • Overloaded forces and stresses on pole due to adverse weather conditions	
Underground Cable (PILC, EPR, and XLPE)	• Moisture ingress (e.g. water treeing) • Corrosion of lead sheaths and dielectric degradation of oil impregnated paper insulation • Corrosion of concentric neutral • Mechanical damage (e.g. due to dig-ins).	• Insulation breakdown leading to complex and prolonged outages • Overheated cable • Potential public safety risk due to dig-in

The ACA relies on the findings from the distribution inspection, testing, and maintenance activities detailed in *Chapter 5.3.3 Asset Lifecycle Optimization Policies and Practices*.

A.1.1 Transformers

Distribution transformers are a vital component to servicing customers from the distribution system at various utilization voltages. Distribution transformers consist of three main installation types: pad-mounted, pole-mounted, or housed within a vault (e.g. submersible transformers). *Chapter 5.3.3 (Section 5.3.3.2)* details the inspection practices for collecting condition factors that are used to establish a Health Index for distribution transformers. Alectra Utilities' total population of in-service distribution-class transformers is 128,362 units. Of these, approximately 65% are Pad Mounted, 25% are Pole Mounted, and 10% are in Vaults. The age distributions for the three transformer types are illustrated in Figure 5.3.2 - 22, Figure 5.3.2 - 23, and Figure 5.3.2 - 24. Among all transformer types, 13,687 transformers are shown to exceed the TUL, of which 3,500 exceed the EUL, representing 10.7% and 2.7%, respectively, of the total population. TUL and EUL values differ for these three transformer types and are shown in the charts.

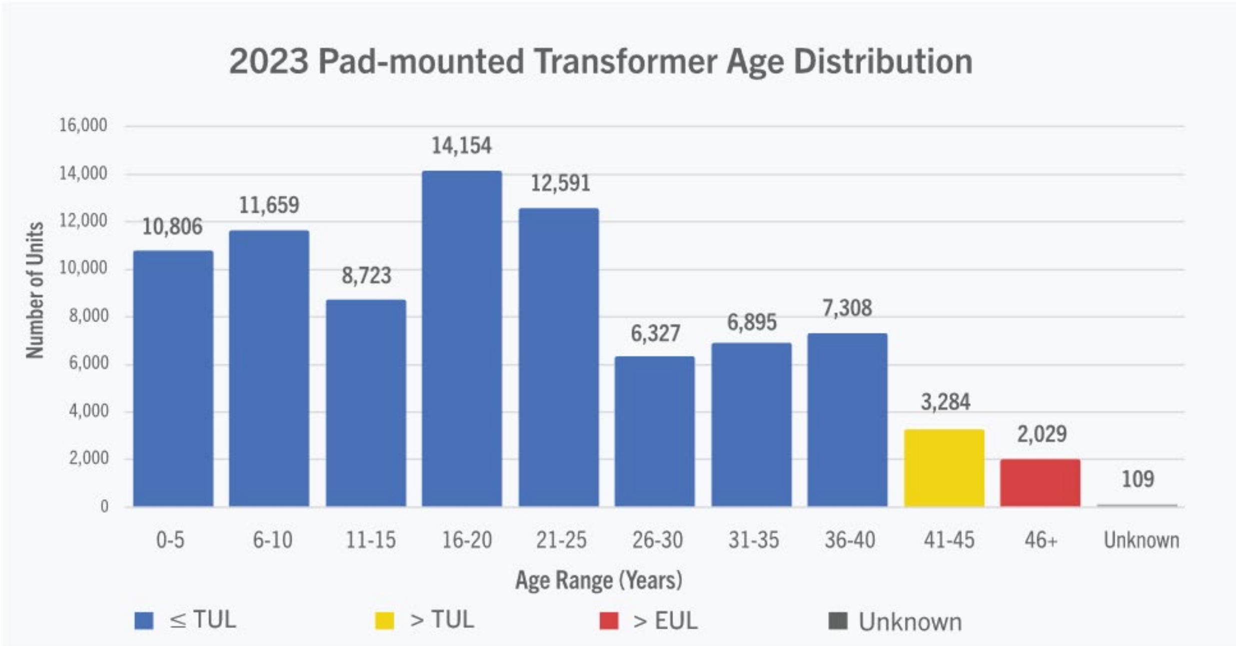

Figure 5.3.2 - 22 Pad-Mounted Distribution Transformer Age Distribution

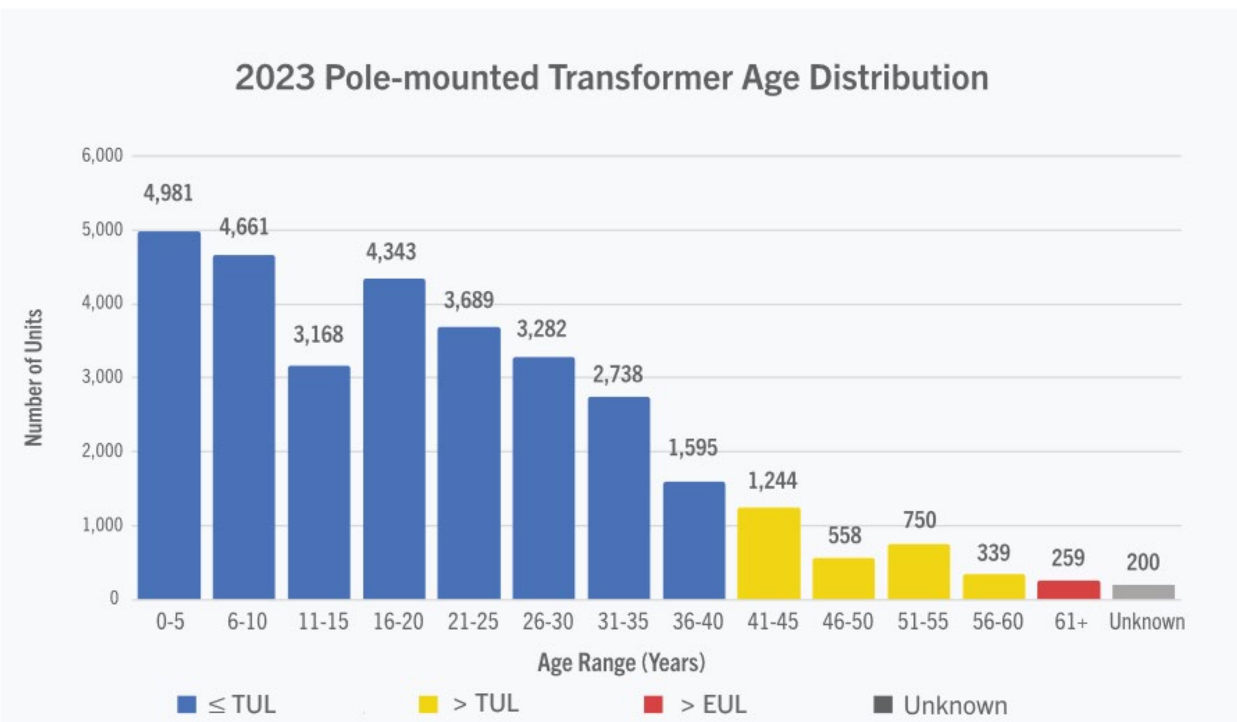

Figure 5.3.2 - 23 Pole-Mounted Distribution Transformer Age Distribution

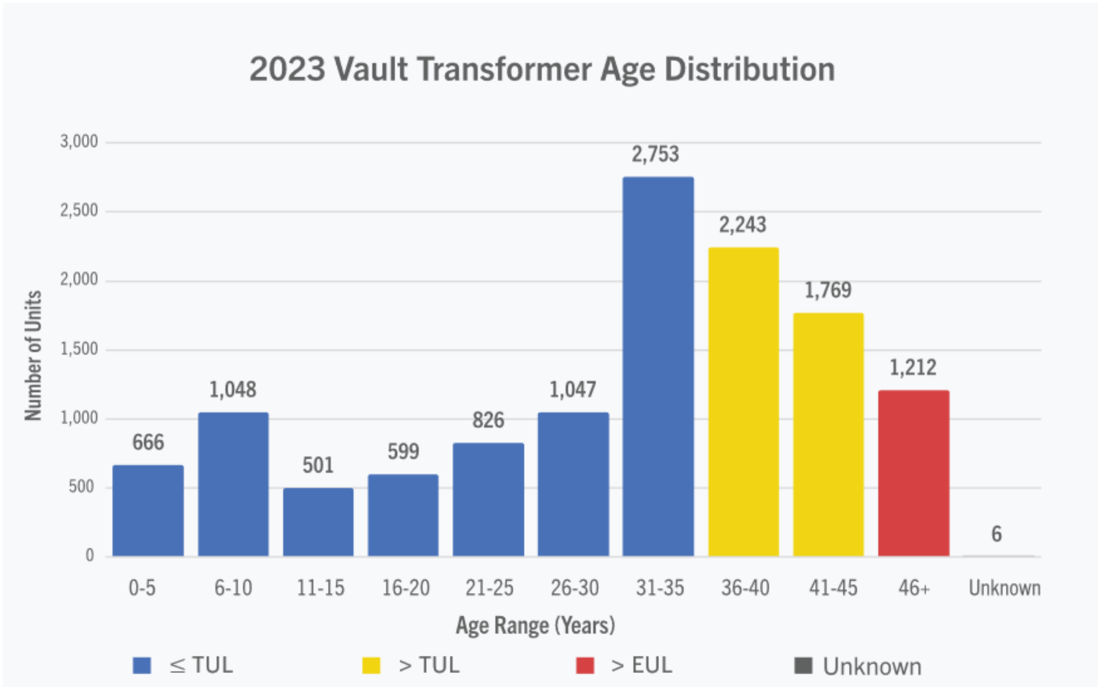

Figure 5.3.2 - 24 Vault Distribution Transformer Age Distribution

The 2023 ACA identified 9,454 transformers, representing 7.4% of total population, in the “Poor” or “Very Poor” Health Index category, as shown in Figure 5.3.2 - 25. This represents a 215% increase when compared to the 2018 ACA, as illustrated in Figure 5.3.2 - 26. The increase can be attributed to assets continuing to deteriorate over time as they are utilized and exposed to environmental conditions. In addition, Alectra Utilities has invested in improving asset health data, including enhancements to the Geographical Information System (GIS), which has led to more accurate ties between collected inspection data to a specific asset and the collection of more detailed and harmonized condition factors. These advancements led to increased visibility into the health of the transformer population, revealing a higher level of deteriorated transformers than previously identified. The HI for distribution transformers is computed by adding the weighted scores of their condition factors, which includes oil leak severity and rust severity. Although age is a factor in the HI calculation, it does not hold significant weight compared to the condition factors collected during inspections.

All transformers in the “Poor” and “Very Poor” HI categories exhibit major degradation, indicating signs of an oil leak or corrosion and posing risks to public safety, reliability, and the environment. Investment options for deteriorated transformers are discussed in *Appendix B03 - Transformer Renewal*.

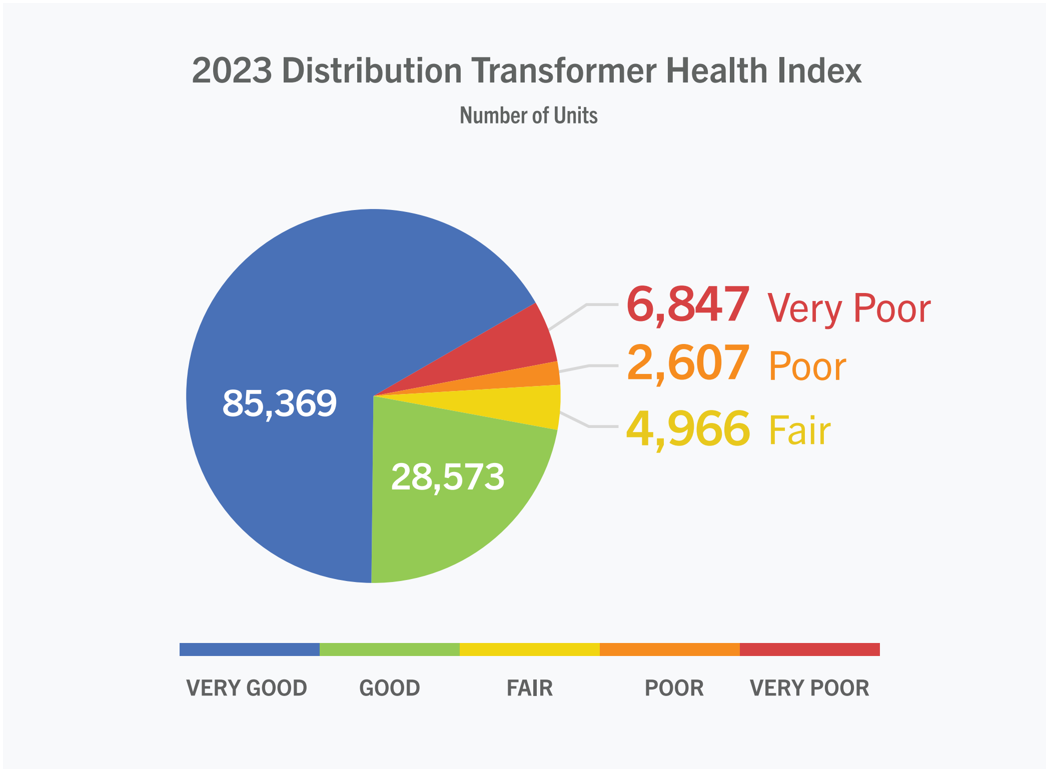

Figure 5.3.2 - 25 Distribution Transformer Health Index

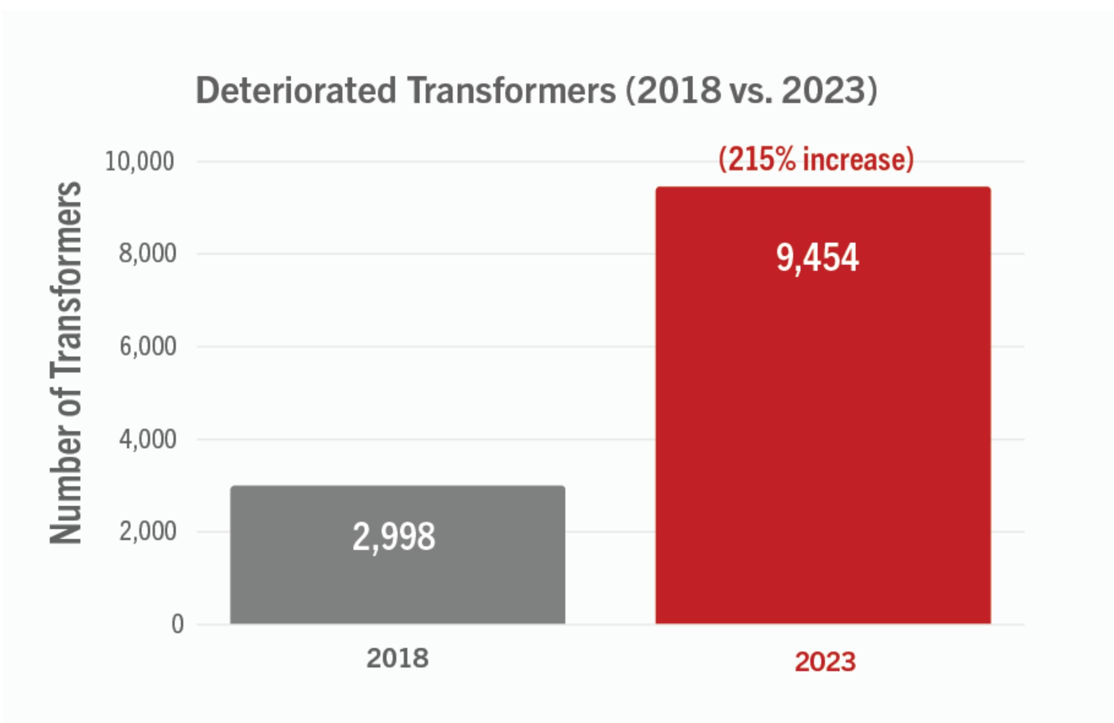

Figure 5.3.2 - 26 Deteriorated Transformer Comparison (2018 vs. 2023)

To illustrate the elevated risks associated with the increase of deteriorated transformers, Figure 5.3.2 - 27 and Figure 5.3.2 - 28 display the HI results geographically in the Alectra East - York Region and Alectra Central (Brampton) planning zones.

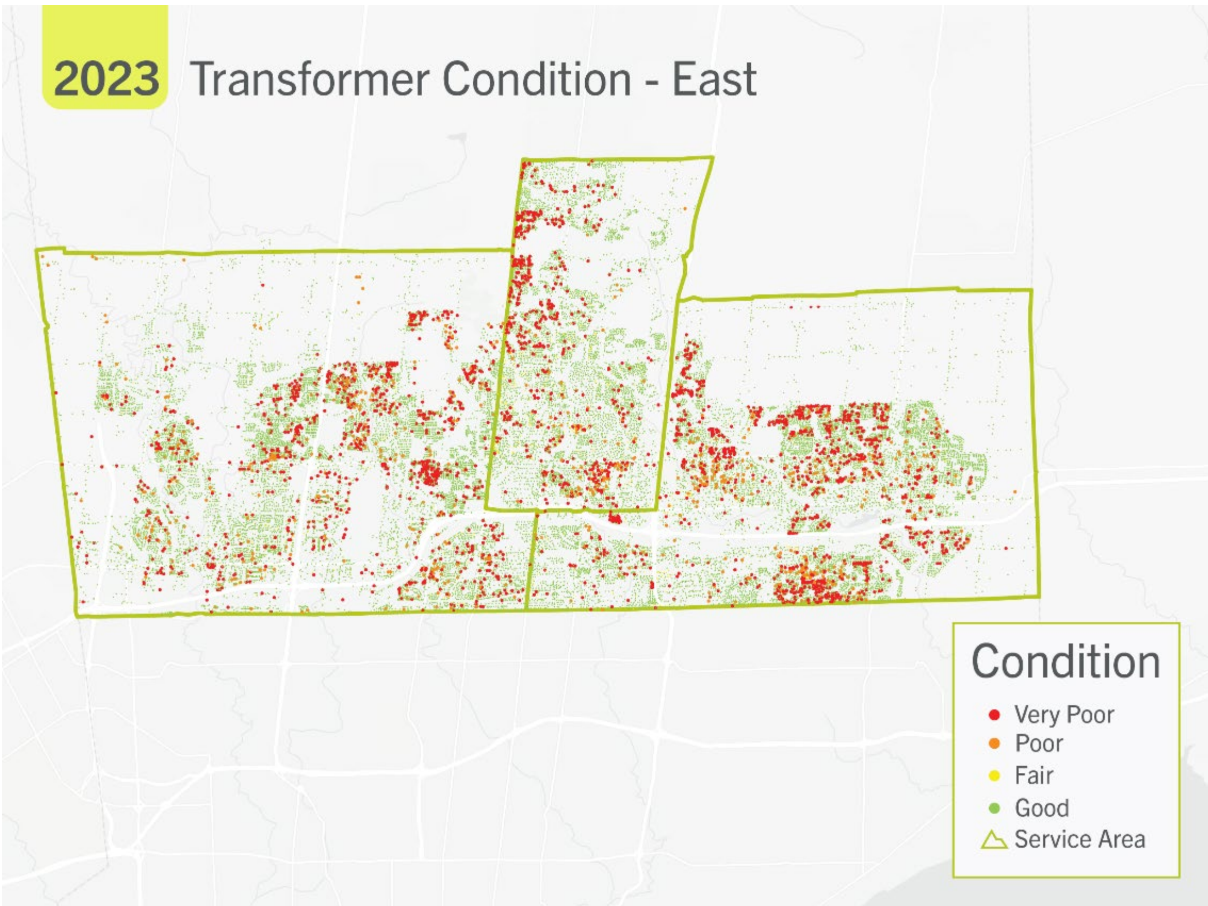

Figure 5.3.2 - 27 York Region – Distribution Transformer Health Index

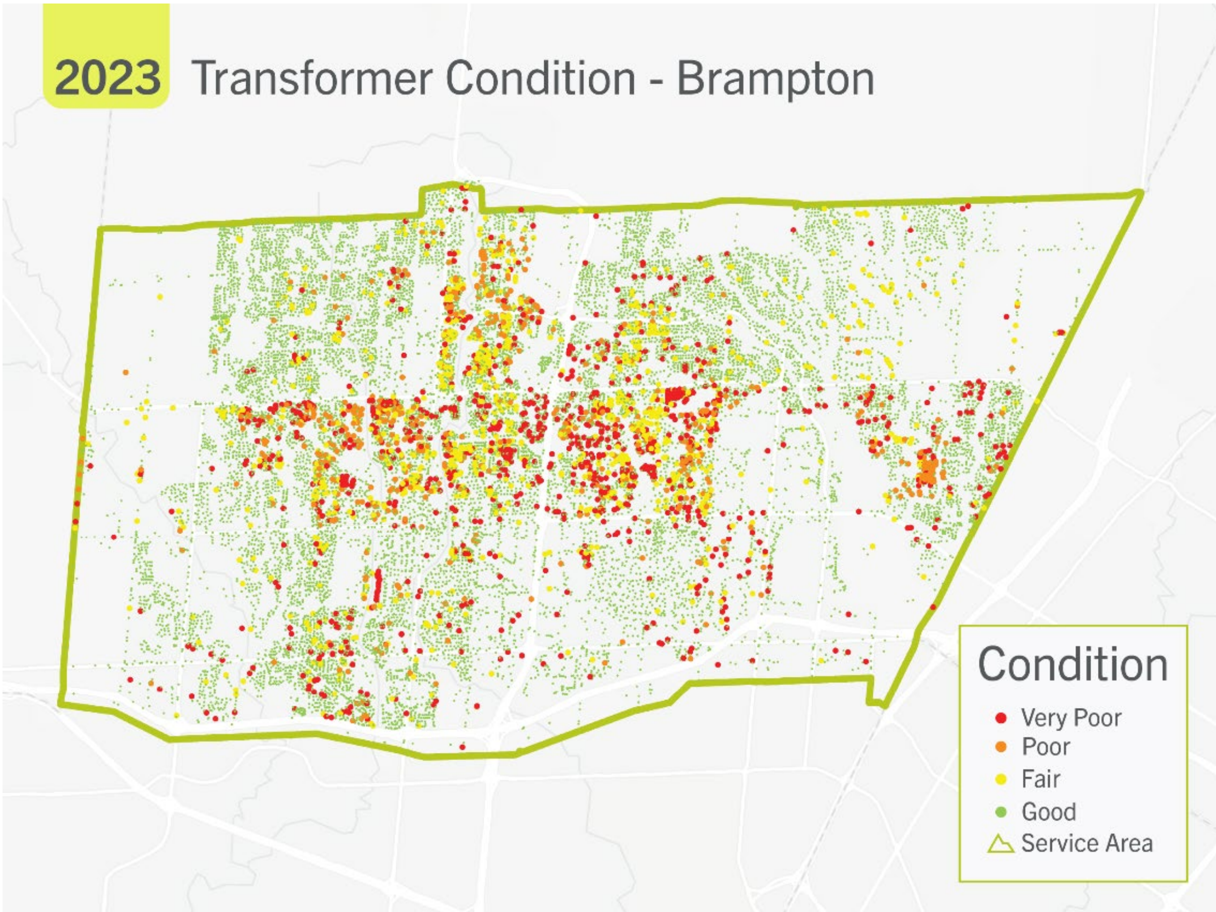

Figure 5.3.2 - 28 Brampton – Distribution Transformer Health Index

Figure 5.3.2 - 29 the increase of identified oil leaks and corrosion (non-mutually exclusive) over the 2021 to 2023 period to the total annual transformer replacement quantities.

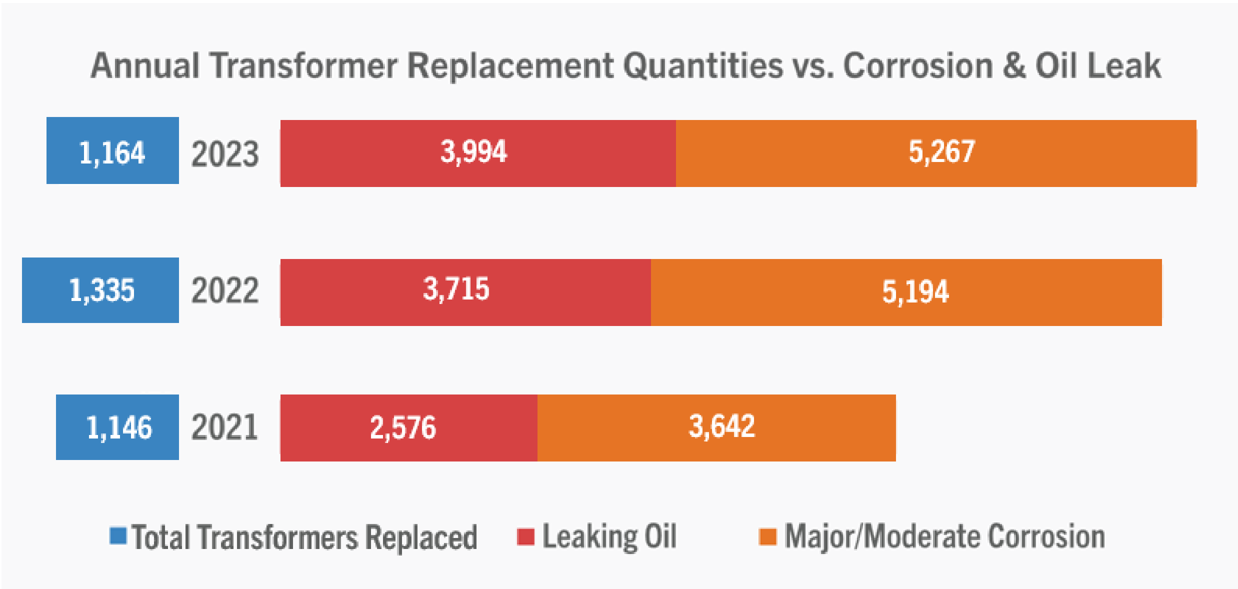

Figure 5.3.2 - 29 Annual Transformer Replacement Quantities vs. Corrosion and Oil Leak Population

Since 2021, identified major and moderately corroded transformers have increased by 45%, while identified oil leaking transformers have increased by 55%. The total replacement quantities (from both a reactive and planned capital perspective) have remained relatively stable, which suggests that the current rate of replacement is not sufficient to stabilize the deteriorated transformer population. This elevated risk underscores the need to shift to a more planned replacement strategy to mitigate safety and environmental risks. The planned and reactive strategies to reverse this trend are discussed in *Appendix B03 - Transformer Renewal* and *Appendix B05 - Reactive Capital*, respectively.

Deteriorated transformers can result in holes forming within the transformer enclosure, which can expose live connections creating a potential public safety risk. In addition, there is a risk of environmental contamination due to leaking oil. From 2021 to 2024, sites where oil leaks contaminated the surrounding environment resulted in an average remediation cost of $50,000. Figure 5.3.2 - 30 illustrates the extent of environmental remediation and the inconvenience it causes to customers.

Figure 5.3.2 - 30 Oil Leak Environmental Remediation in Backyard (Mississauga, 2019)

Examples of oil leaking and corroded pad-mounted transformers are shown in Figure 5.3.2 - 31.

<table>
<tr><th>Pad-Mounted Transformer Oil Leak Example #1</th><th>Pad-Mounted Transformer Oil Leak Example #2</th></tr>
<tr><td>Evidence of an oil spill on the ground and surrounding environment.</td><td>Evidence of oil running down the surface of the unit but no evidence of an oil spill on the ground.</td></tr>
<tr><td>
</td><td></td></tr>
<tr><th>Pad-Mounted Transformer Example #1</th><th>Pad-Mounted Transformer Corrosion Example #2</th></tr>
<tr><td>Rusted through (hole); unit is no longer sealed due to corrosion.</td><td>Rusting at the weld or seams.</td></tr>
<tr><td></td><td>
</td></tr>
</table>

Figure 5.3.2 - 31 Pad-Mounted Transformer Oil Leak and Corrosion Severity Examples

Asset sustainment practices for transformers are detailed in *Chapter 5.3.3 (Section 5.3.3.3 A.1)* Investment options for transformers are detailed in *Appendix B03 - Transformer Renewal*.

A.1.2 Switchgear

Distribution-class pad-mounted switchgear facilitates the connection of local distribution circuits to main line underground feeder cable systems as well as interconnecting main line feeder circuits. Switchgear are a critical component in the distribution system that help reduce the impact of outage or maintenance activity and improve service reliability. Switchgear units are used for isolating, sectionalizing, and fusing for laterals, and reconfiguring cable loops for maintenance, restoration, and other operating requirements. They enable the provision of service to residential subdivisions and commercial and industrial customers via fused connections to main feeder cable systems. A single switchgear failure can impact up to 5,000 customers. *Chapter 5.3.3 (Section 5.3.3.2)* details the inspection practices for collecting condition factors that are used to establish a Health Index for distribution-class pad-mounted switchgear.

Alectra Utilities' in-service population of distribution-class pad-mounted switchgear totals 3,444 units, including a combination of air-insulated, oil-filled, solid-dielectric, and sulfur hexafluoride (SF_6) switchgear. Switchgear may be manually operated, motor operated on-site, or remotely operable via Supervisory Control and Data Acquisition (SCADA) system. According to industry averages, a pad-mounted switchgear has a TUL of 30 years and an EUL of 45 years. However, air-insulted switchgear operating on the 27.6kV system have different life characteristics. Based on Alectra's and industry experience, the TUL for these units is 20 years and EUL is 35 years. A breakdown of the age distribution is illustrated in Figure 5.3.2 - 32, 447 of all pad-mounted switchgear have exceeded the TUL, of which 51 exceed the EUL, representing 13% and 1.5%, respectively, of the total installed population.

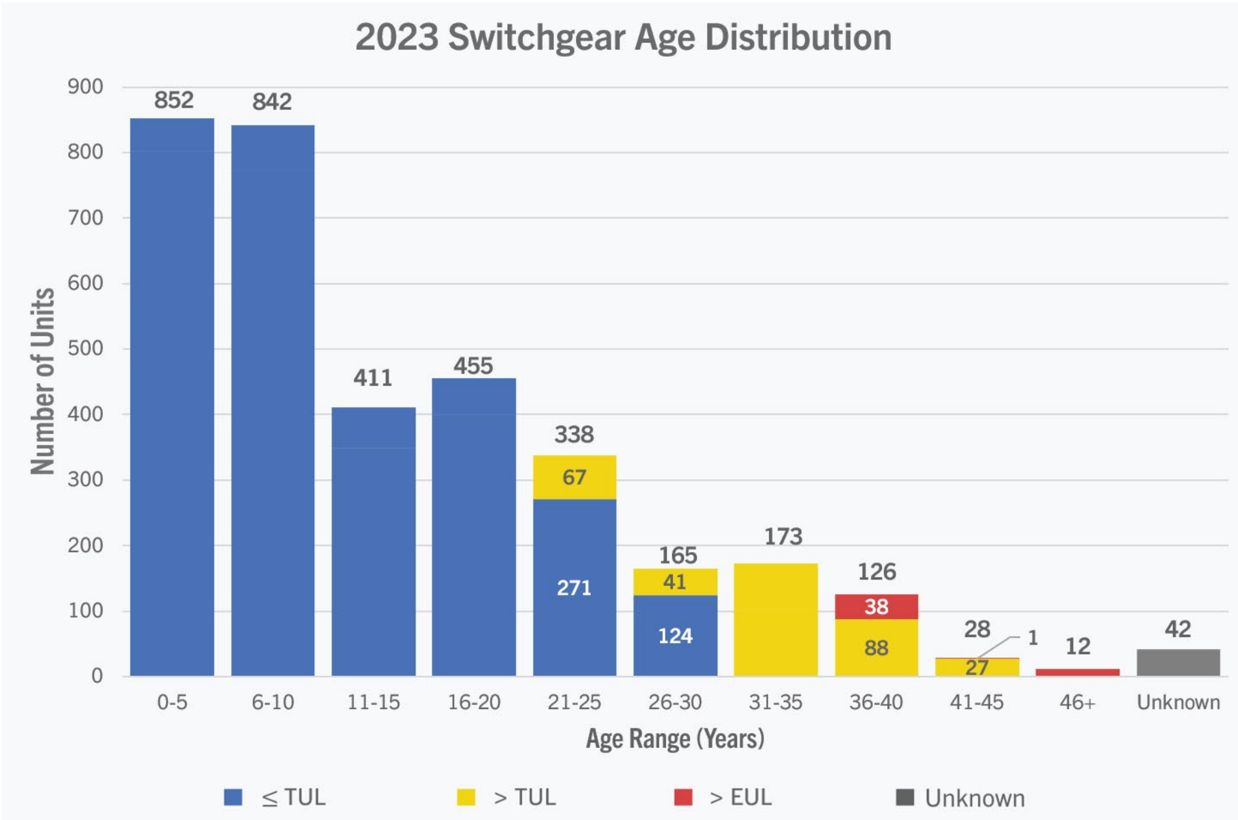

Figure 5.3.2 - 32 Switchgear Age Distribution

The 2023 ACA identified 329 pad-mounted switchgear, representing 9.6% of total population, in the "Poor" or "Very Poor" Health Index category, as shown in Figure 5.3.2 - 33. Investment options for deteriorated switchgear are discussed in *Appendix B02 - Underground Renewal*. Switchgear degradation depends on several factors, such as condition of mechanical components, contamination, and corrosion. The HI for distribution switchgear is computed by adding the weighted scores of their condition factors, which includes oil leak severity, rust severity, and other internal component deficiencies such as switch and insulation damage. ACA models for switchgear incorporate weighted degradation factors specific to the different types of in-service switchgear (i.e. air-insulated, oil-filled, solid-dielectric, and SF_6 switchgear). Although age is a factor in the HI calculation, it does not hold a significant weight compared to the condition factors collected during inspections.

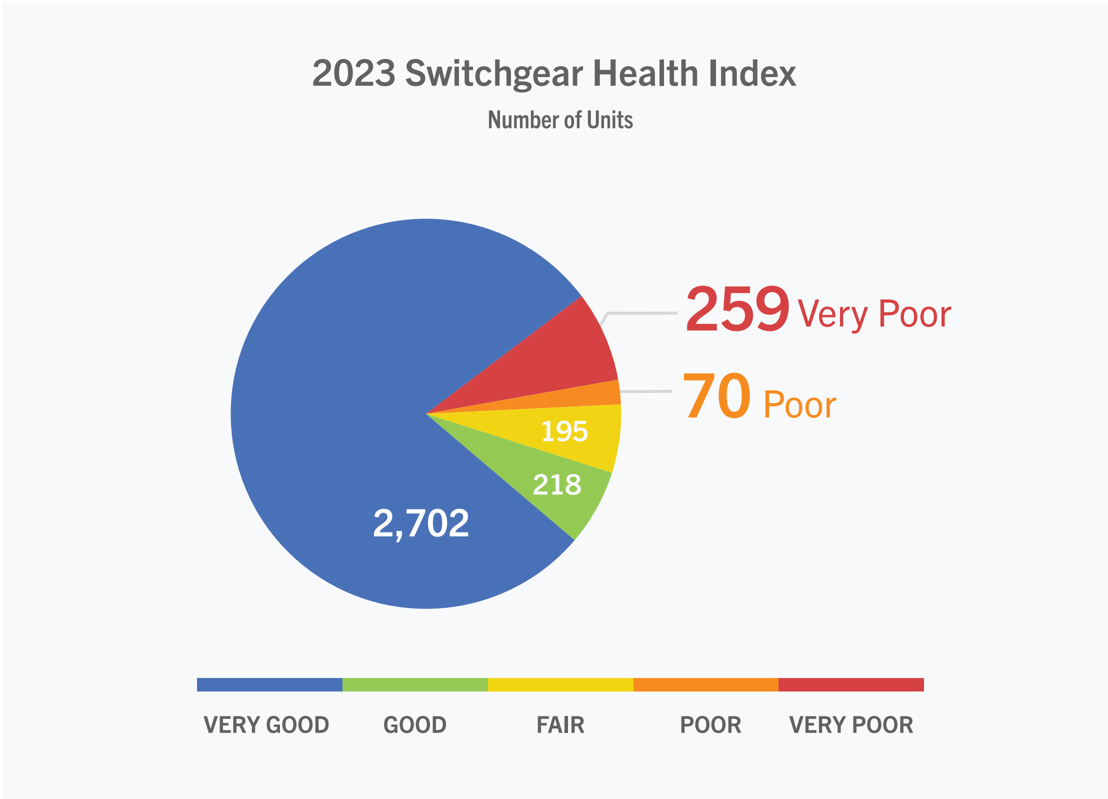

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Figure 5.3.2 - 33 Switchgear Health Index

Figure 5.3.2 - 34 compares the increase of deficiencies over the 2021 to 2023 period to the total annual replacement quantities.

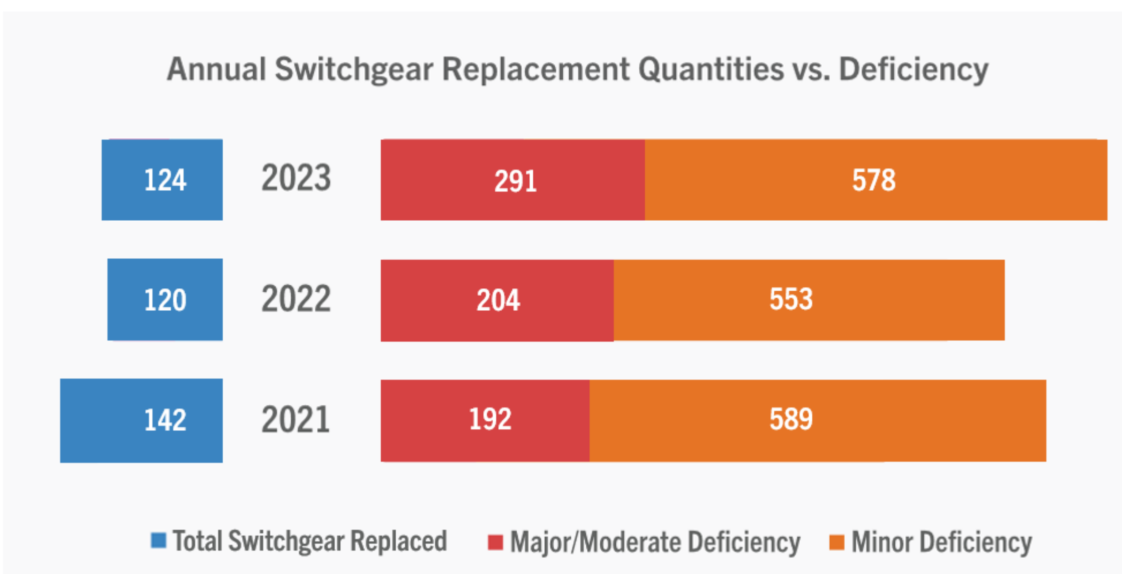


Figure 5.3.2 - 34 Annual Switchgear Replacement Quantities vs. Deficiencies

Since 2021, major and moderate deficiencies have increased by 52%. Switchgear deficiencies can be external or internal, including major corrosion resulting in live connections becoming exposed, flashovers, and insulation breakdown. Examples of external deficiencies are shown in Figure 5.3.2 - 35 and examples of internal deficiencies are shown in Figure 5.3.2 - 36.

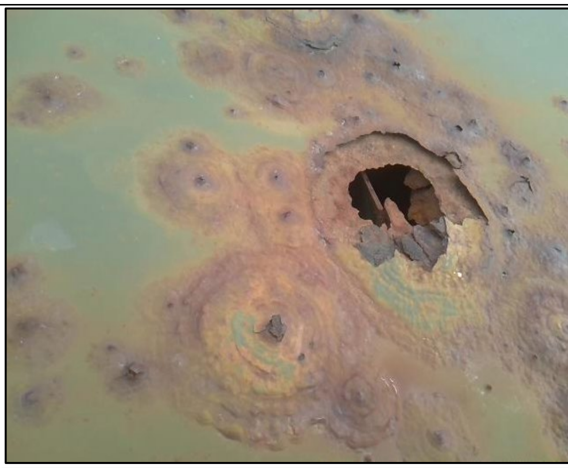
Switchgear Corrosion Example #1	**Switchgear Corrosion Example #2**
Rusted through (hole); unit is no longer sealed due to corrosion.	Rusting at the weld or seams.
• Switchgear 74, Brampton (Air-Insulated) • Replaced July 2023 (Solid Dielectric)	• Switchgear SG1138, Mississauga (Air-Insulated) • Replaced December 2024 (Solid Dielectric)
 	 

Figure 5.3.2 - 35 Switchgear Corrosion Examples

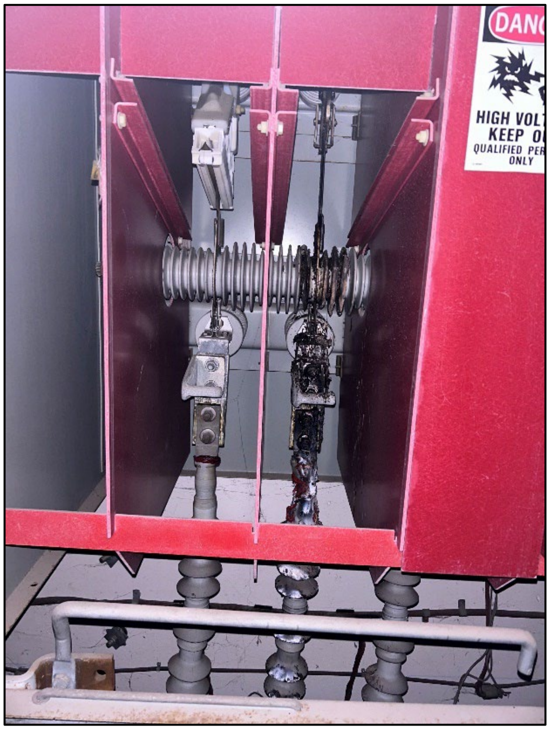
Switchgear Flashover Example	Switchgear Insulation Breakdown Example
	

Figure 5.3.2 - 36 Switchgear Internal Component Damage Examples

Responding to switchgear failures reactively results in prolonged outages not acceptable to customers. Figure 5.3.2 - 37 summarizes the customer hours of interruption (CHI) over the past 11 years (2014-2024) due to switchgear failures. Over the 2014-2018 period, the average CHI was 26,678 hours, which compares to the 2019-2024 average CHI of 36,130 hours. The increasing trend of CHI suggests that the recent rate of replacement is not sufficient to maintain stable customer outage levels associated with switchgear failures. These units continue to deteriorate over time and have been negatively impacting customer reliability.

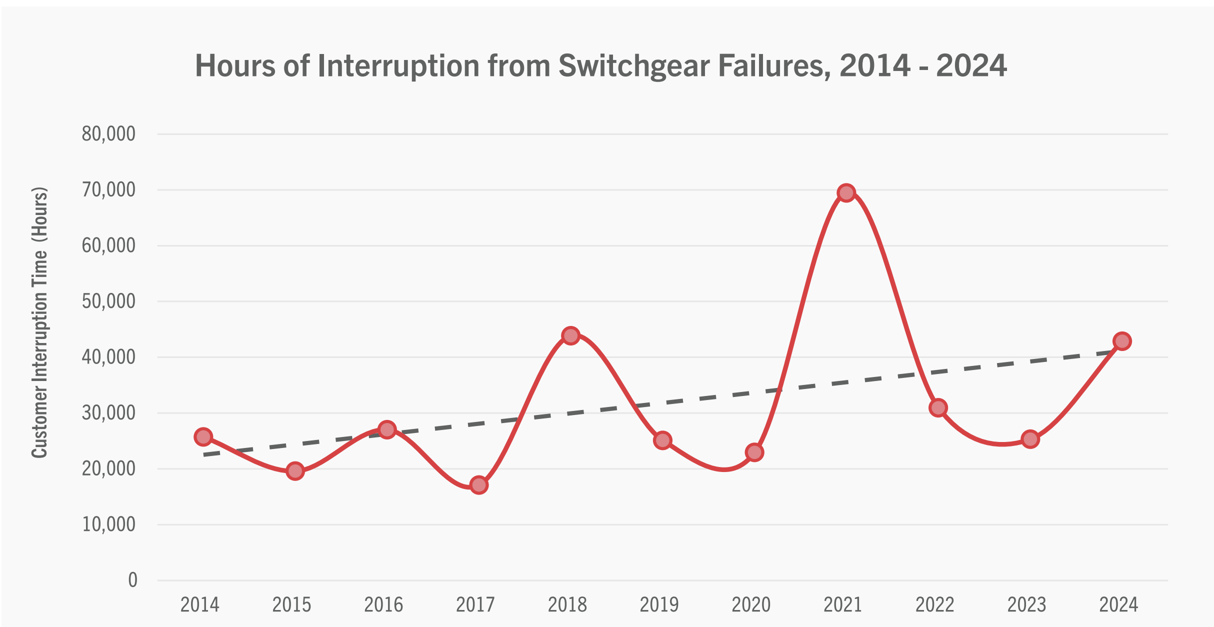


Figure 5.3.2 - 37 Customer Hours of Interruption from Switchgear Failures (2014-2024)

Failure to replace deteriorated switchgear can result in high-impact outages with large customer counts. Asset sustainment practices for distribution switchgear are detailed in *Chapter 5.3.3* (*Section 5.3.3.3 A.2*). Investment options for deteriorated switchgear are discussed in *Appendix B02 - Underground Renewal*.

A.1.3 Overhead Switches

Overhead switches are the primary method for switching supply for system operation and to restore customers after an outage. Overhead switches also enable Alectra Utilities to sectionalize and isolate parts of the distribution system when needed. The main switch types in Alectra Utilities' distribution system include SF_6 and solid-dielectric insulated units with vacuum interrupters and air-insulated load interrupters. These types of switches are referred to as Load

Interrupter Switches (LIS). *Chapter 5.3.3 (Section 5.3.3.2)* details the inspection practices for collecting condition factors that are used to establish a Health Index for overhead switches.

Alectra Utilities' distribution system includes 3,192 overhead switches of varying types and configuration. Figure 5.3.2 - 38 illustrates the age distribution of this switch population. A total of 183 overhead switches exceed the TUL of 40 years, of which 40 exceed the EUL of 55 years, representing 5.7% and 1.3%, respectively, of the total installed population.

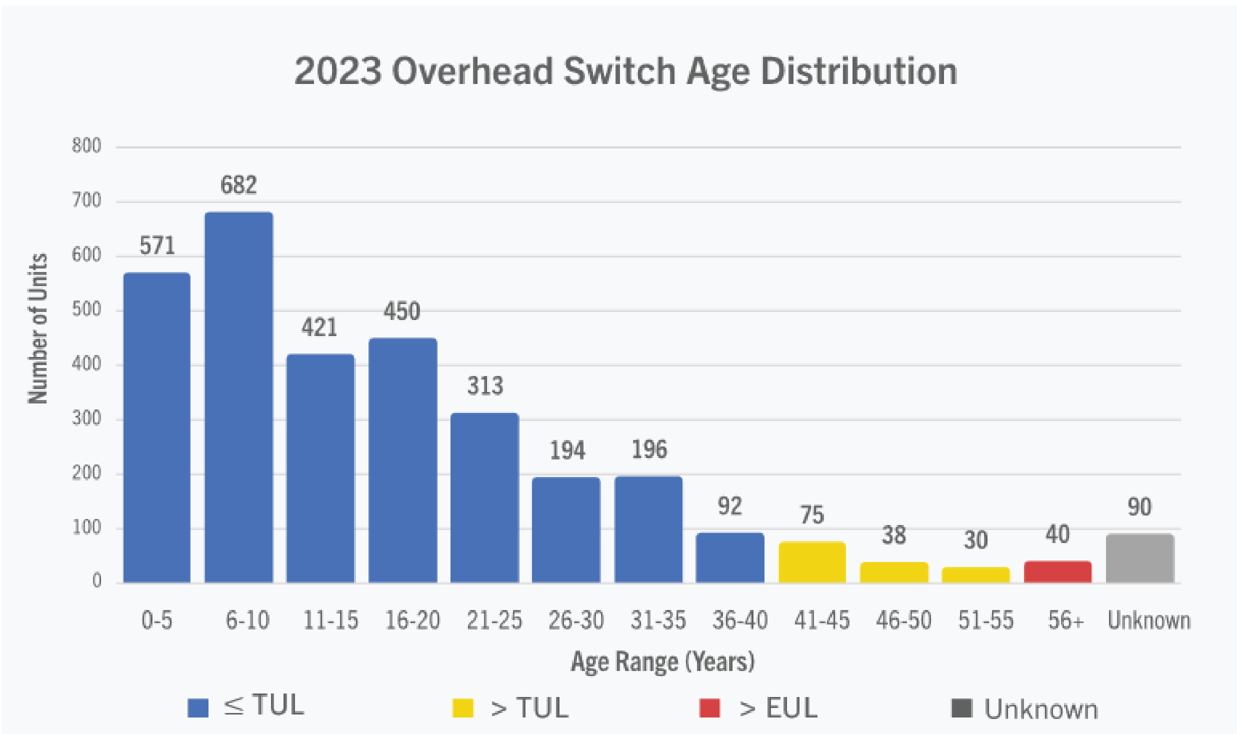


Figure 5.3.2 - 38 Overhead Switch Age Distribution

The 2023 ACA identified 80 overhead switches in “Poor” or “Very Poor” Health Index, as illustrated in Figure 5.3.2 - 39. The HI for overhead switches is computed by adding the weighted scores of their condition factors, which are collected during inspection (e.g. signs of cracks, rust or burn marks) or maintenance (e.g. inoperability). Although age is a factor in the HI calculation, it does not hold a significant weight compared to the condition factors collected during inspections.

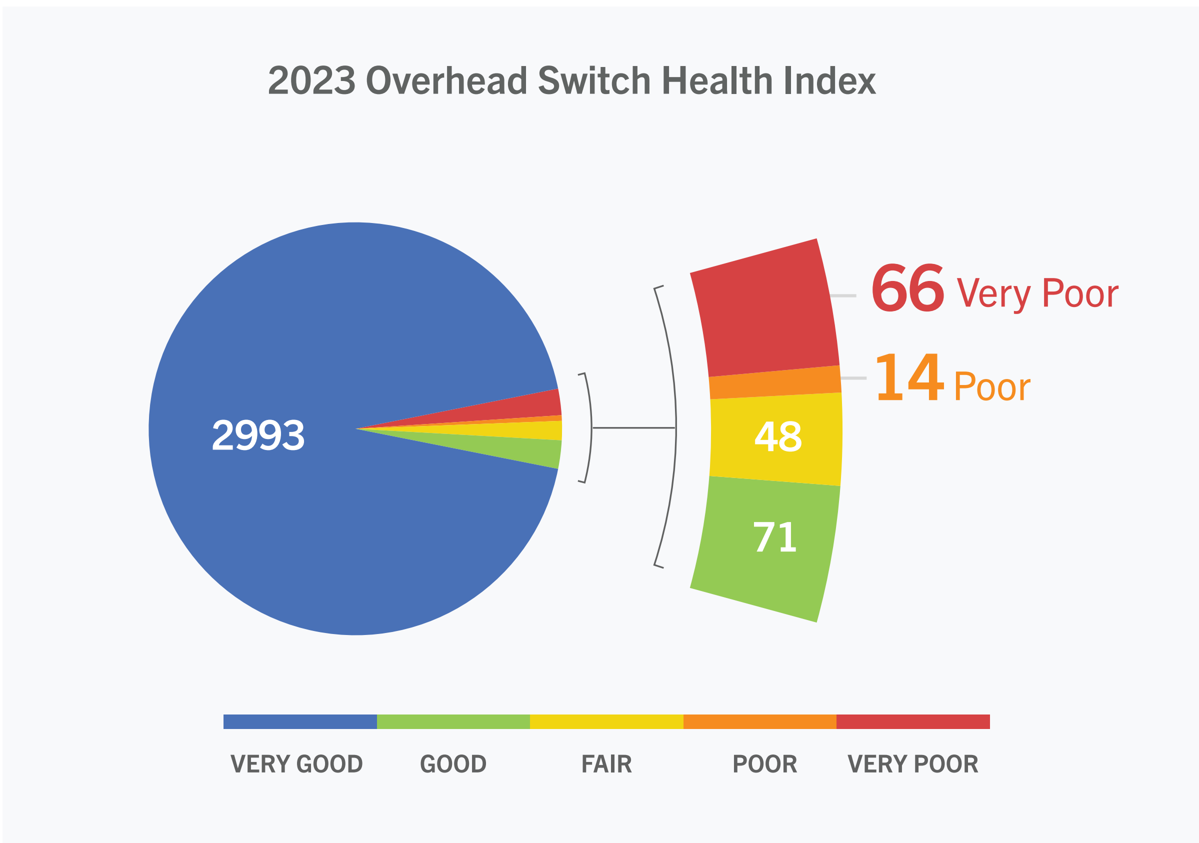


Figure 5.3.2 - 39 Overhead Switch Health Index

Replacements of deteriorated overhead switches are a high priority to maintain the safe and reliable operation of the distribution system and reduce the outage impact to customers. Failure to replace deteriorated overhead switches can also result in high-impact outages with large customer counts. An example of a deteriorated switch is shown in Figure 5.3.2 - 40.

Figure 5.3.2 - 40 Mississauga – Flash Marks on Switch

Asset sustainment practices for overhead LIS switches are detailed in *Chapter 5.3.3 (Section 5.3.3.3 A.3)*. Investment options for overhead LIS switches are discussed in *Appendix B01 - Overhead Renewal*.

A.1.4 Overhead Conductors

Overhead conductors in Alectra Utilities' distribution system vary in size and vintage. Certain sized legacy conductor types have demonstrated an elevated risk of failure, and experienced failures that led to dangerous "wire down" incidents. The conductors involved are vintage #6 wire gauge or smaller, which typically remain in-service from older, lower voltage primary systems (e.g. 4.16kV and 8.32kV) and are currently considered undersized. Due to the physical properties of this conductor type and the cyclic nature of loading, these conductors become brittle over time and can fail at junctions where conductors are supported or terminated. Due to their overhead configuration, these conductors are exposed to weather events such as wind and ice loading, which further increase their probability of failure.

Alectra Utilities' distribution system has 18,463KM of overhead conductors. Figure 5.3.2 - 41 illustrates Alectra Utilities' age distribution for overhead conductor. A total of 564KM of overhead conductor exceed the TUL of 60 years, of which 49KM exceed the EUL of 75 years, representing 3.1% and 0.3%, respectively, of the total installed population

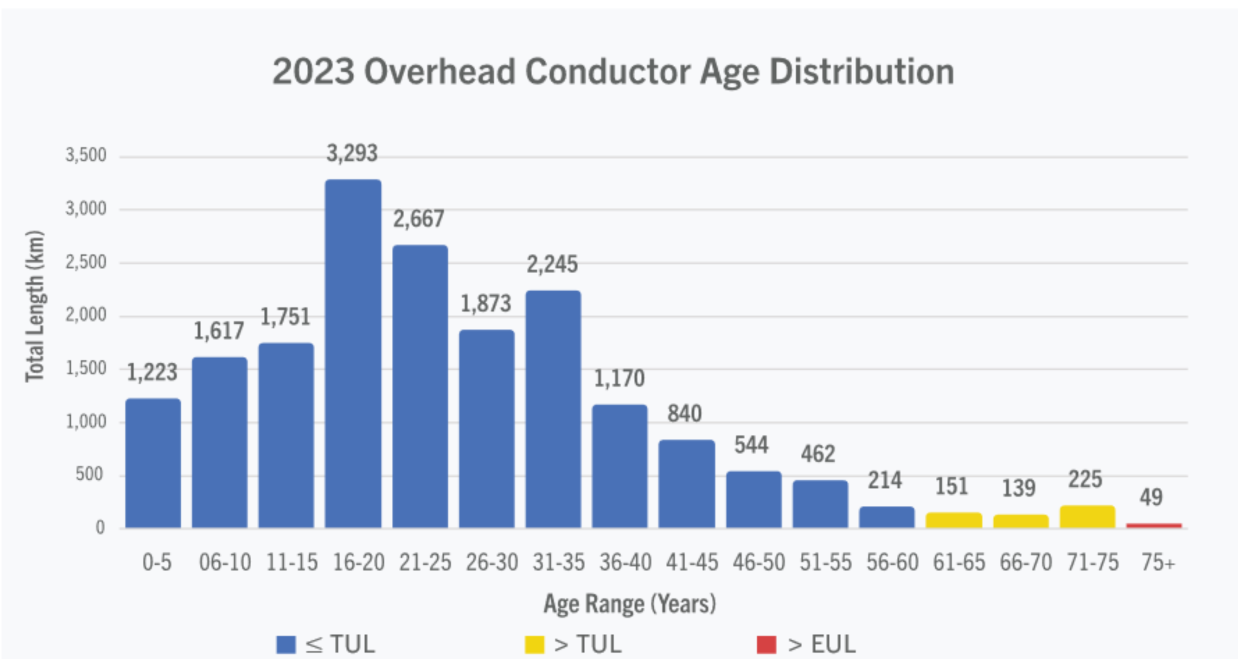
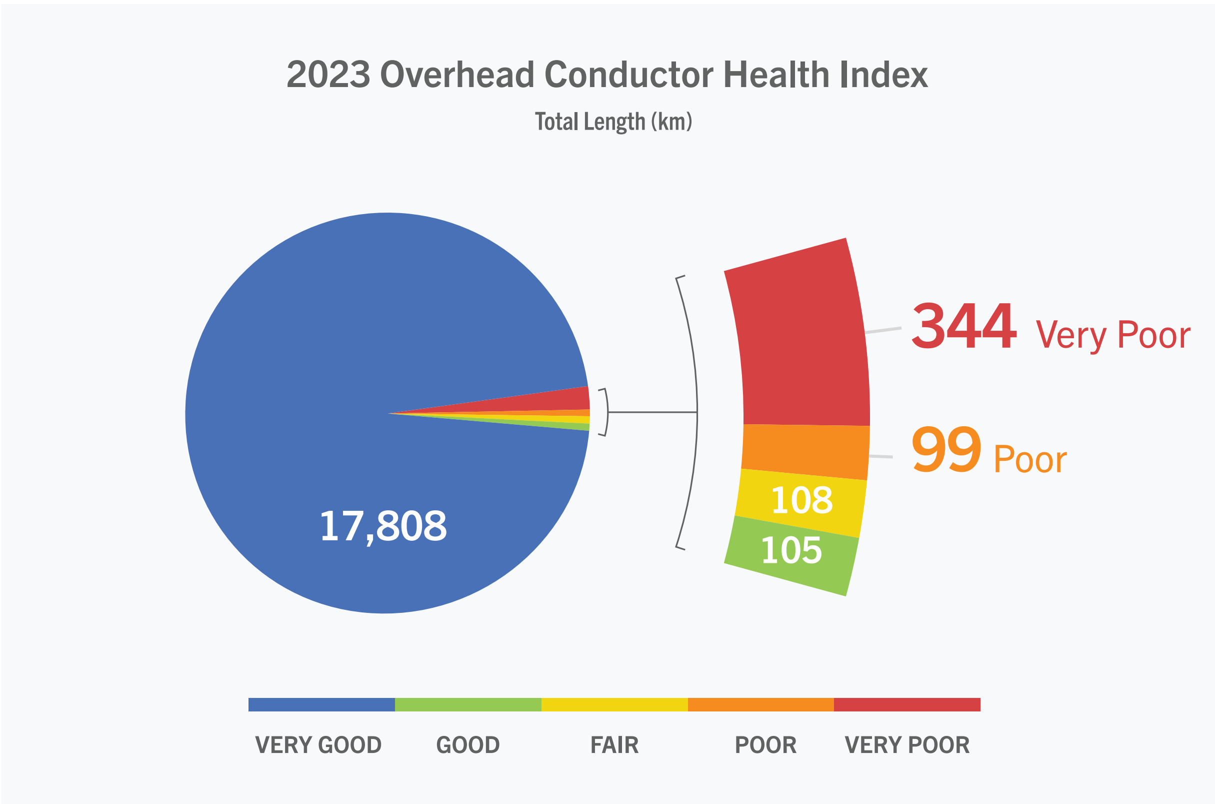


Figure 5.3.2 - 41 Overhead Conductor Age Distribution

1 The 2023 ACA identified 443KM of overhead primary conductor with a “Poor” or “Very Poor” Health Index score, as illustrated in Figure 5.3.2 - 42.

3 

4 **Figure 5.3.2 - 42 Overhead Conductor Health Index**

Failure to replace deteriorated overhead conductors may lead to wire-down events, posing significant safety risks to the public. Figure 5.3.2 - 43 shows a broken wire due to undersized conductor. Undersized overhead conductors, such as #6 copper, have also been identified as a public safety risk by the Electrical Safety Authority (ESA).

Figure 5.3.2 - 43 Hamilton – Fallen Undersized Wire

Asset sustainment practices for overhead conductors are detailed in *Chapter 5.3.3 (Section 5.3.3.2 A.4)*. Investment options for overhead conductors are discussed in *B01 - Overhead Renewal*.

A.1.5 Poles

Wood and concrete poles support Alectra Utilities' overhead distribution plant, including overhead conductors, transformers, switches, streetlights, and telecommunication attachments. Poles play a critical role in enabling the safe and reliable delivery of electricity to customers.

The combination of severe weather, along with reduced strength (identified during field testing and visual inspection), can lead to failure scenarios where multiple poles lose their structural integrity and fail, possibly falling to the ground. Restoring power to customers in this scenario may take up to 12-24 hours depending on severity of the event. It is imperative that Alectra Utilities monitors and assesses the condition of the poles to avoid significant safety and reliability risks with prolonged outages. *Chapter 5.3.3 (Section 5.3.3.2)* details the inspection practices for collecting condition factors that are used to establish a Health Index for wood and concrete poles.

Alectra Utilities' overhead distribution system includes 134,372 poles, of which 105,262 are wood poles and 29,110 are concrete poles. Pole age distribution for wood and concrete poles are illustrated in Figure 5.3.2 - 44 and Figure 5.3.2 - 45, respectively. A total of 26,018 wood and concrete poles combined, representing 19.4% of total population exceed the TUL of 45 and 60 years, respectively. Among these, 1,489 poles, representing 1.1% of the total population, exceed the EUL of 75 and 80 years, respectively.

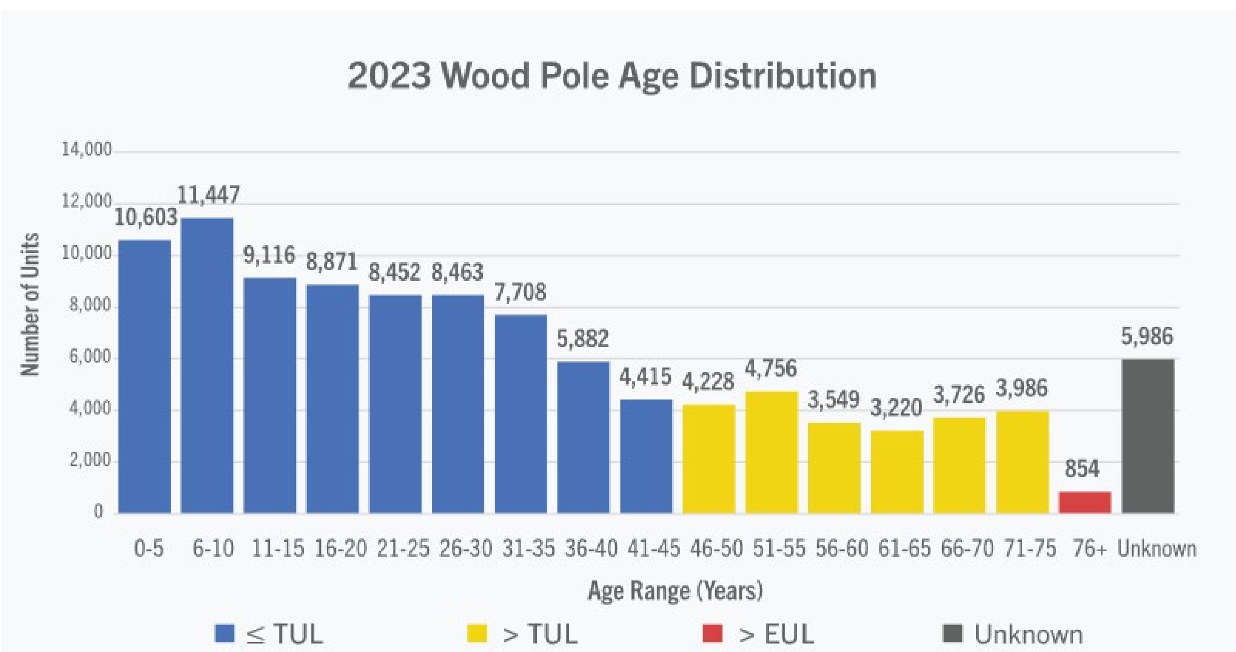


Figure 5.3.2 - 44 Wood Pole Age Distribution

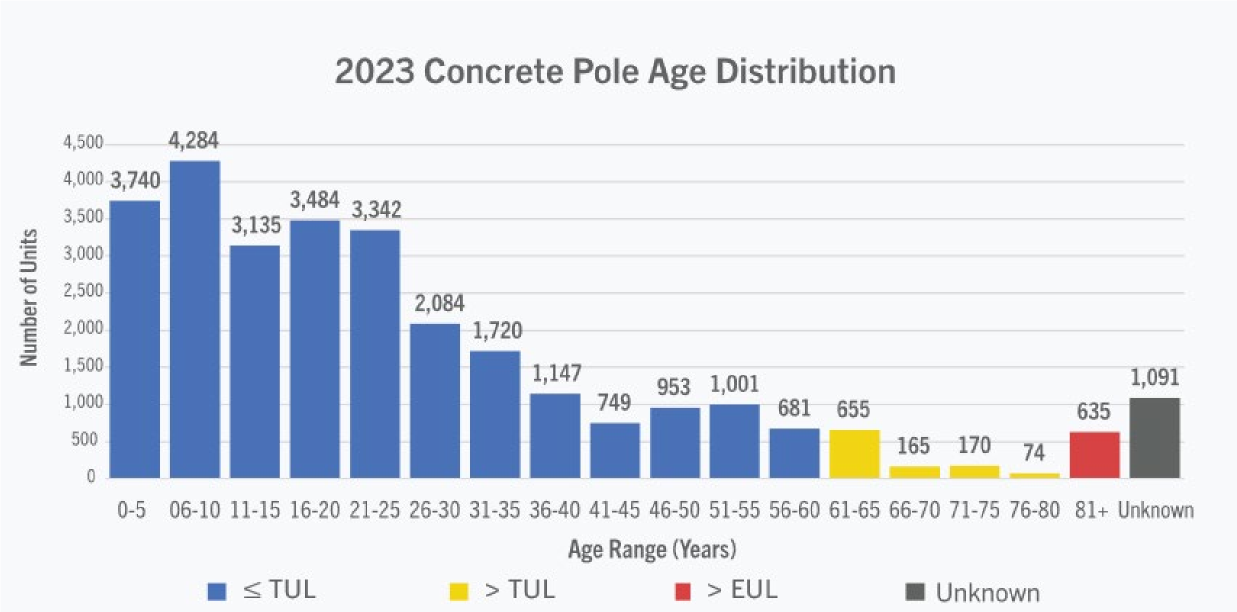


Figure 5.3.2 - 45 Concrete Pole Age Distribution

The 2023 ACA identified 9,691 wood poles and 586 concrete poles, representing 7.6% of total pole population, in "Poor" or "Very Poor" HI, as illustrated in Figure 5.3.2 - 46 and Figure 5.3.2 - 47. This represents a 4% increase when compared to 2018 ACA as per Figure 5.3.2 - 48. All poles in the "Poor" and "Very Poor" HI categories exhibit major degradation. Key degradation indicators for wood poles include rot and feathering at the top of the pole, shell and ground line rot, and pole defects, including horizontal cracks or electrical burns. Key degradation indicators for concrete poles include rust and corrosion of the re-bar, cracking, concrete spalling, and mechanical damage. Investment options for deteriorated poles are discussed in *Appendix B01 - Overhead Renewal*. The HI for wood and concrete poles is computed by adding the weighted scores of their condition factors (e.g. ground line rot and cracks). Although age is a factor in the HI calculation, it does not hold a significant weight compared to the condition factors collected during inspections.

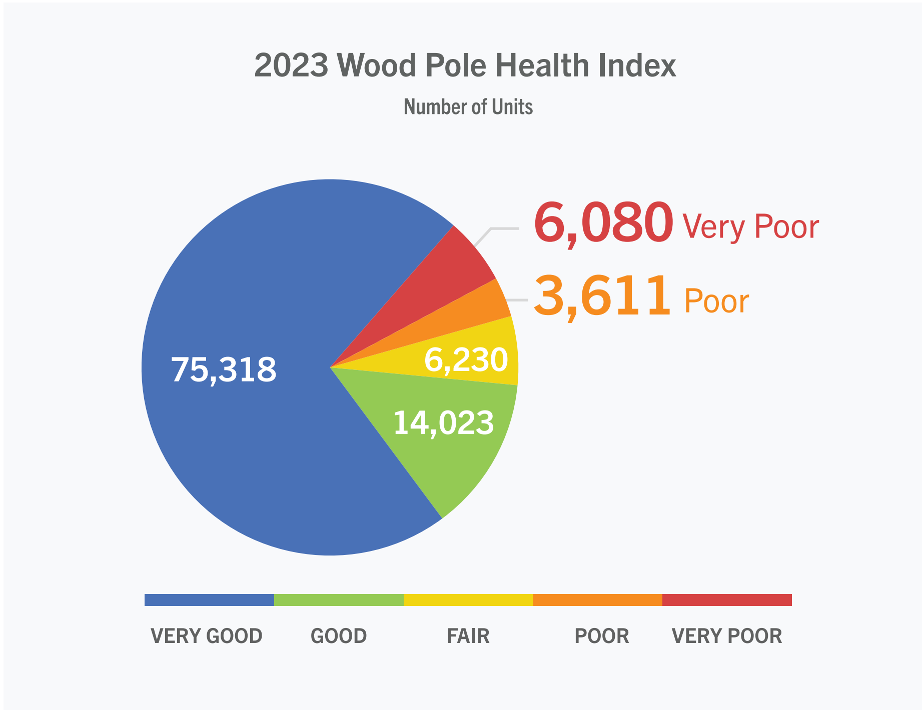


Figure 5.3.2 - 46 Wood Pole Health Index

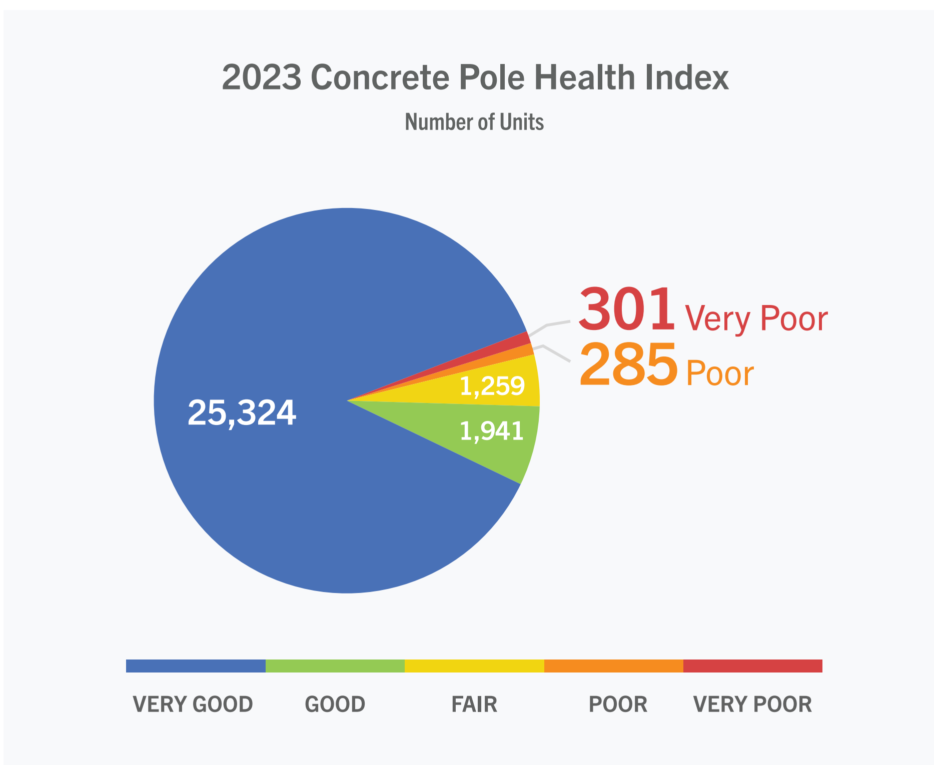


Figure 5.3.2 - 47 Concrete Pole Health Index

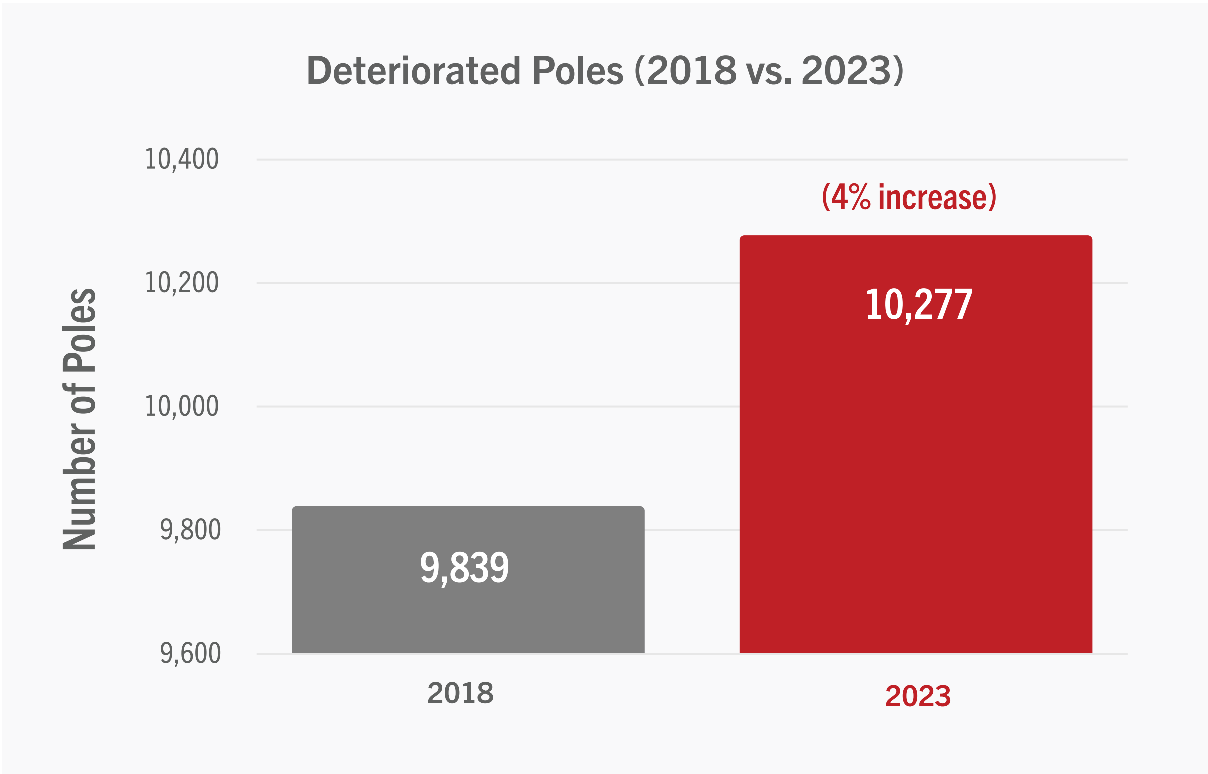


Figure 5.3.2 - 48 Deteriorated Pole Comparison (2018 vs. 2023)

To illustrate the elevated safety and reliability risk associated with the increase of deteriorated poles, Figure 5.3.2 - 49 and Figure 5.3.2 - 50 display the HI results geographically in Hamilton and St. Catharines sub-planning zones.

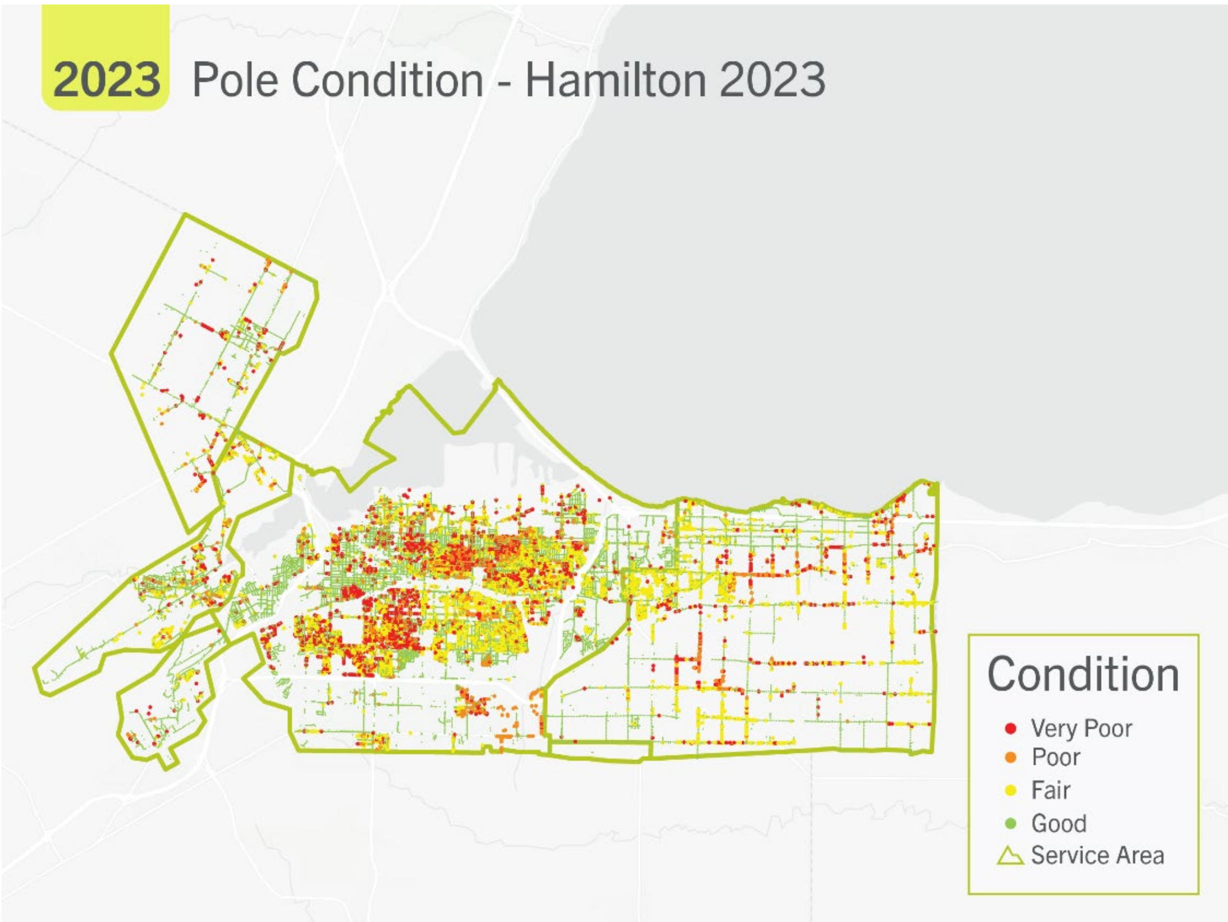


Figure 5.3.2 - 49 Hamilton – Pole Health Index

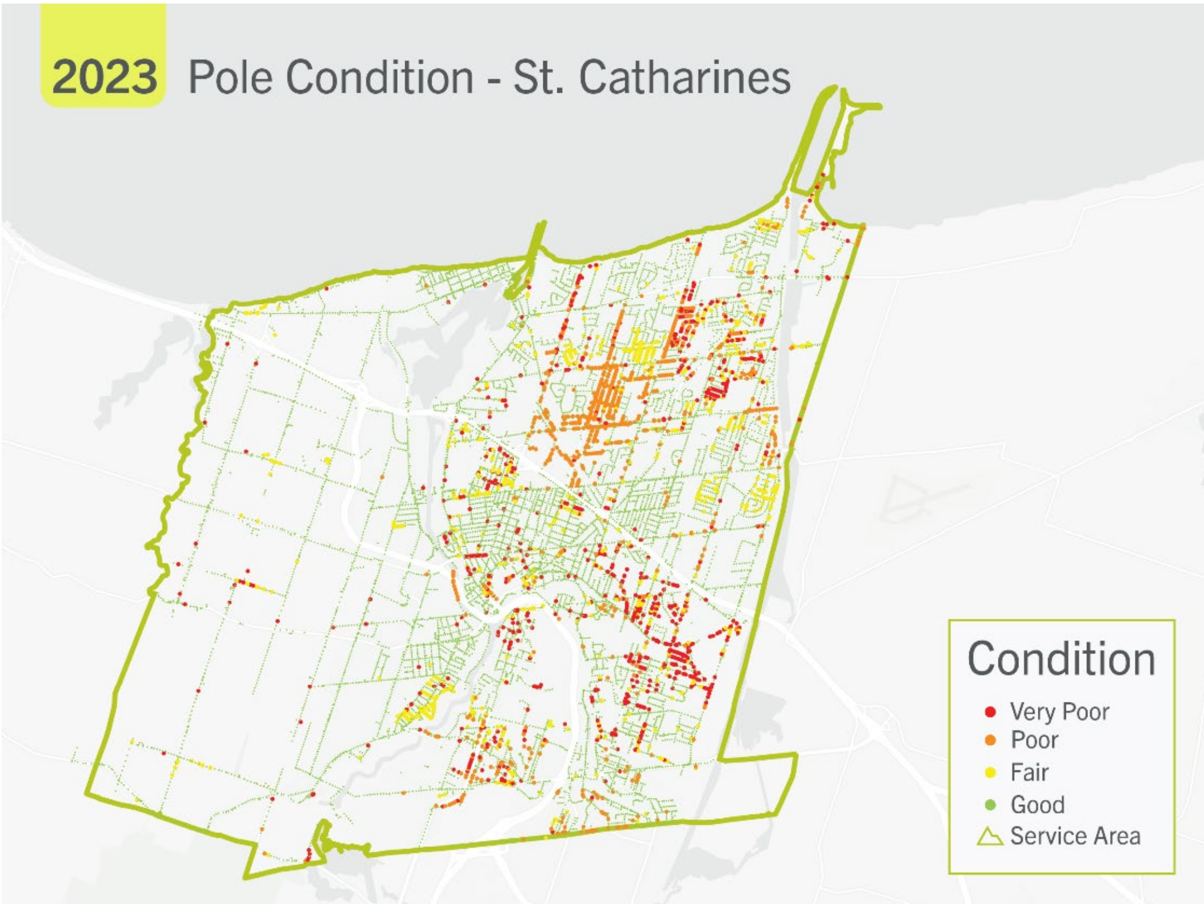


Figure 5.3.2 - 50 St. Catharines – Pole Health Index

Alectra Utilities has increased planned pole replacement volumes to stabilize the asset deterioration trend. However, current volumes remain insufficient to arrest the growth in deteriorated poles (refer to *Appendix B01 - Overhead Renewal* for the proposed investment levels and pacing). Examples of deteriorated wood and concrete poles are shown in Figure 5.3.2 - 51 and Figure 5.3.2 - 52, respectively.

Wood Pole Ground Line Rot Example	**Wood Pole Fire Damage Example**	**Wood Pole Top Feathering Examples**
Significant rot and decay (large cavities) at the base of the pole	Wood loss due to charring affecting structural integrity	Wood splitting at the top of the pole affecting pole-top attachments
		

Figure 5.3.2 - 51 Deteriorated Wood Pole Examples

Concrete Pole Exposed Rebar Example	Concrete Pole Cracking/Spalling Example
Rebar is exposed, posing significant reliability and safety risks	Large pieces of concrete falling off the pole
	

Figure 5.3.2 - 52 Deteriorated Concrete Pole Examples

On December 12, 2024, the failure of three wood poles in “Very Poor” condition in Mississauga precipitated the collapse of nine poles, including one concrete pole.Figure 5.3.2 - 53 and Figure 5.3.2 - 54 show examples of the damaged and fallen poles from this incident.

Figure 5.3.2 - 53 Deteriorated and Fallen Wood Pole in Mississauga, December 2024

Figure 5.3.2 - 54 Damaged and Fallen Concrete Pole in Mississauga, December 2024

Alectra Utilities completed a Climate Risk and Vulnerability Assessment detailed in *Section 5.3.2.1 C*. The study projects a higher frequency of extreme weather events, such as the 2022 Derecho event. A Derecho event, projected to occur once every four years within Alectra Utilities' service territory, poses a significant risk to the overhead distribution system. On May 21, 2022, a Derecho swept across Alectra Utilities service area with wind gusts of 120KM/h. The storm impacted approximately one-third of customers and resulted in 101 poles being reactively replaced. It took approximately 12.5 hours to restore 90% of the customers due to the need to rebuild multiple pole lines.

The climate assessments indicate that the majority of Alectra Utilities' service territory will see more of these high wind events, increasing in severity and intensity. According to the Climate Risk and Vulnerability Assessment and Alectra Utilities' additional analysis of climate vulnerability of its wood and concrete poles population, there are 29,092 poles potentially vulnerable to adverse weather, with 4,387 being classified as high-risk. Alectra Utilities uses the climate-vulnerability status of each pole, and the locational wind severity risk (informed by the climate vulnerability study detailed in *Section 5.3.2.1 C*) to further prioritize replacement of deteriorated poles.

Figure 5.3.2 - 55 and Figure 5.3.2 - 56. show damaged and fallen poles as a result of this major storm.

Figure 5.3.2 - 55 Fallen Pole Line Caused by High Winds in Brampton, May 2022

Figure 5.3.2 - 56 Pole Damage Caused by High Winds in Brampton, May 2022

Alectra Utilities must mitigate public safety risks, maintain system reliability, and account for customer preferences (refer to *Exhibit 1, Tab 5, Schedule 2 Application-Specific Customer Engagement*) to ensure that the distribution system is resilient to adverse environmental events.

Alectra Utilities has a significant level of deteriorated wood poles, increasing the risk of pole failure and susceptibility to severe weather events. Pole failures are a safety risk to the public and can lead to high-impact outages. Hence, planned replacements are designed to address the deteriorated population while reducing the impact of storms by replacing poles in vulnerable areas using present-day standards.

Asset replacement practices for poles are detailed in *Chapter 5.3.3 (Section 5.3.3.3 A.5)*. Investment options for poles are discussed in *Appendix B01 - Overhead Renewal*.

A.1.6 Underground Cable

Alectra Utilities owns and operates 23,694KM of underground primary cable, comprised of paper insulated lead covered (PILC) cable, ethylene propylene rubber-insulated (EPR) cable, and cross-linked polyethylene (XLPE) cable.

Primary underground cables are critical to the delivery of electrical service across Alectra Utilities' service territory. Underground distribution cables are commonly utilized in urban areas, where it is beneficial over overhead infrastructure for increased reliability and safety considerations. Insulation failures is a primary cause of faults on these cables. Repair efforts are complicated by the location of faults, especially in urban areas, often occurring beneath customer properties, which results in extended power outages. Figure 5.3.2 - 57 illustrates Alectra Utilities' cable population by cable type.

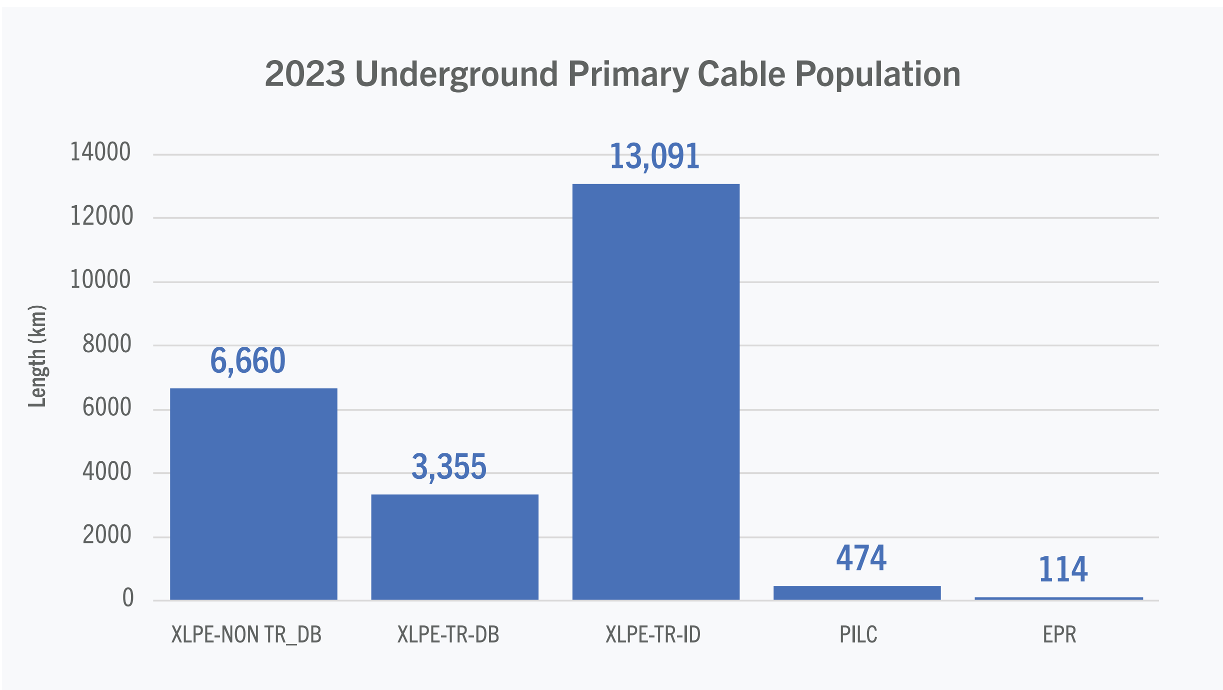


Figure 5.3.2 - 57 Underground Primary Cable Population

A breakdown of the age distribution across all cable types is illustrated in Figure 5.3.2 - 58.

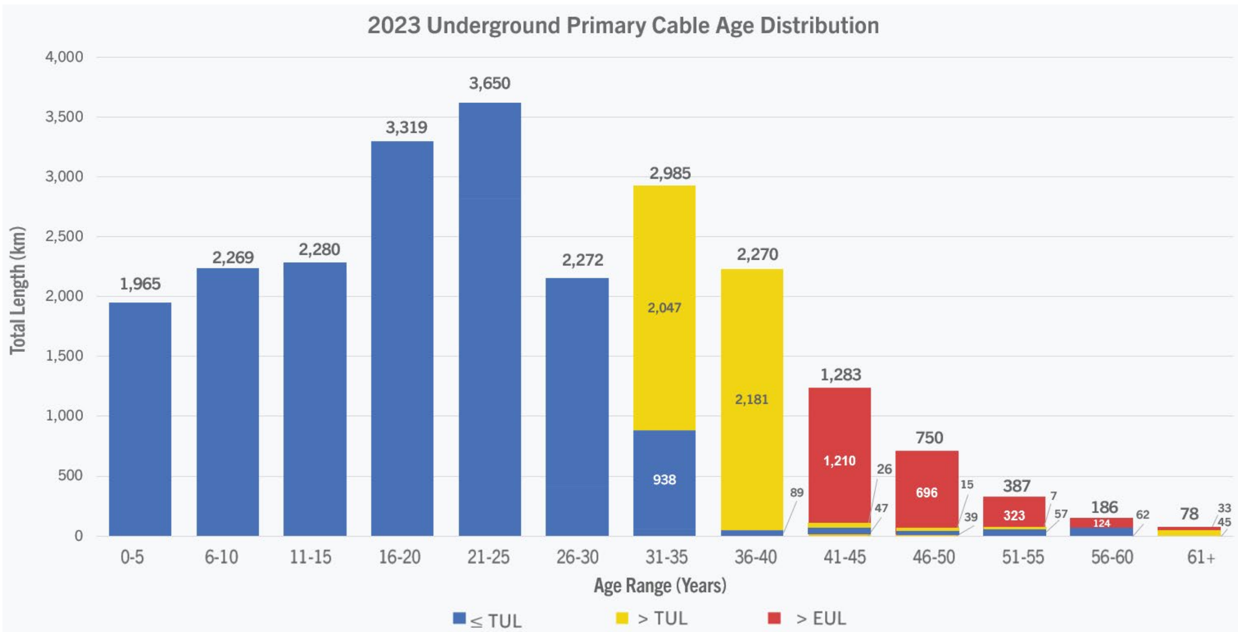


Figure 5.3.2 - 58 Primary Underground Cable Age Distribution

Asset sustainment practices for underground cables are detailed in *Chapter 5.3.3 (Section 5.3.3.2 A.6*). The respective HI results and risks for each cable type are discussed in *Section 5.3.2.5 A.1.6.1* to *Section 5.3.2.5 A.1.6.3*.

A.1.6.1 PILC Cable

PILC represents 2% of Alectra Utilities' primary cable population. PILC cables are hermetically sealed with a lead sheath, protecting the cable from humidity and outside elements. These cables can be constructed with a single conductor or multiple conductors. In Alectra Utilities' service territory, a majority of the PILC cables contain three conductors and are typically installed in a 3.5-inch duct. Long term degradation mechanisms of PILC cables include corrosion of the lead sheath and dielectric degradation of the oil impregnated paper insulation, leading to insulation breakdown and localized failures. When PILC cable fails, the faulted portion is removed, and the remaining functional cables are spliced through and returned to service.

A breakdown of the age distribution is illustrated in Figure 5.3.2 - 59. A total of 56KM of PILC cable exceed the TUL of 60 years, of which 11KM exceed the EUL of 70 years, representing 11.8% and 2.3%, respectively, of the total installed population.

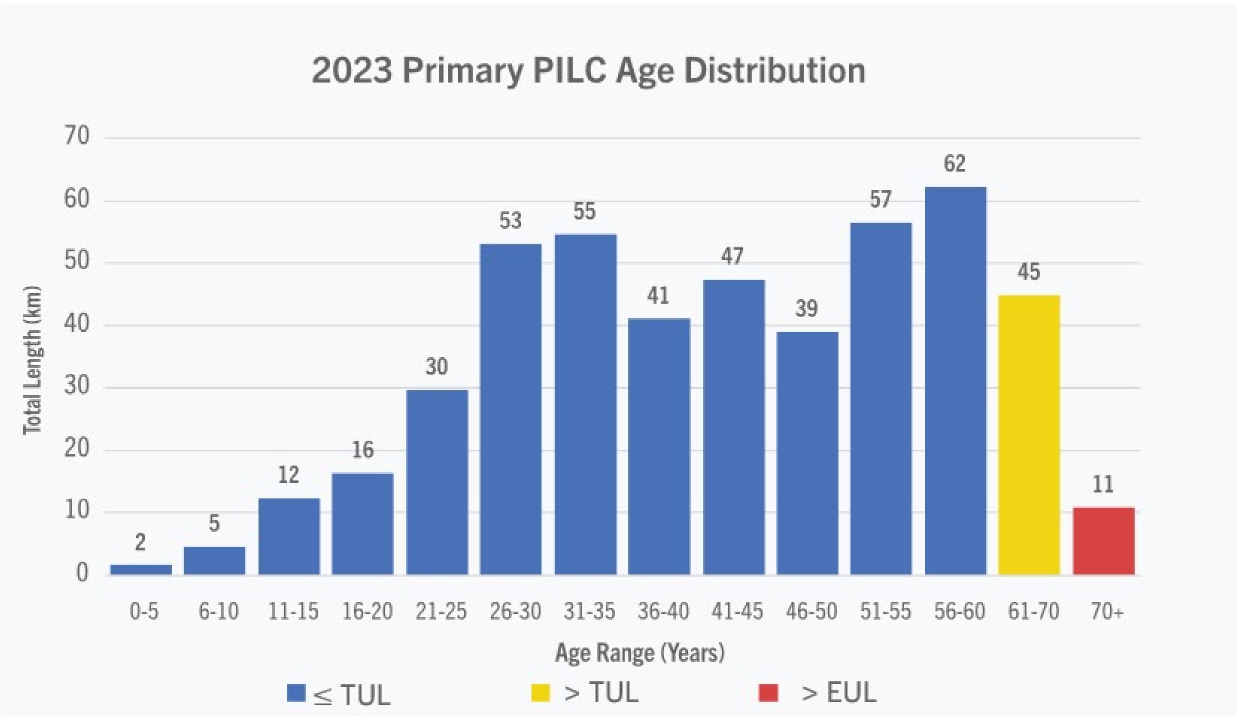


Figure 5.3.2 - 59 Underground Primary PILC Cable Age Distribution

The 2023 ACA identified 39KM of underground PILC cable in a "Poor" or "Very Poor" Health Index, as illustrated in Figure 5.3.2 - 60.

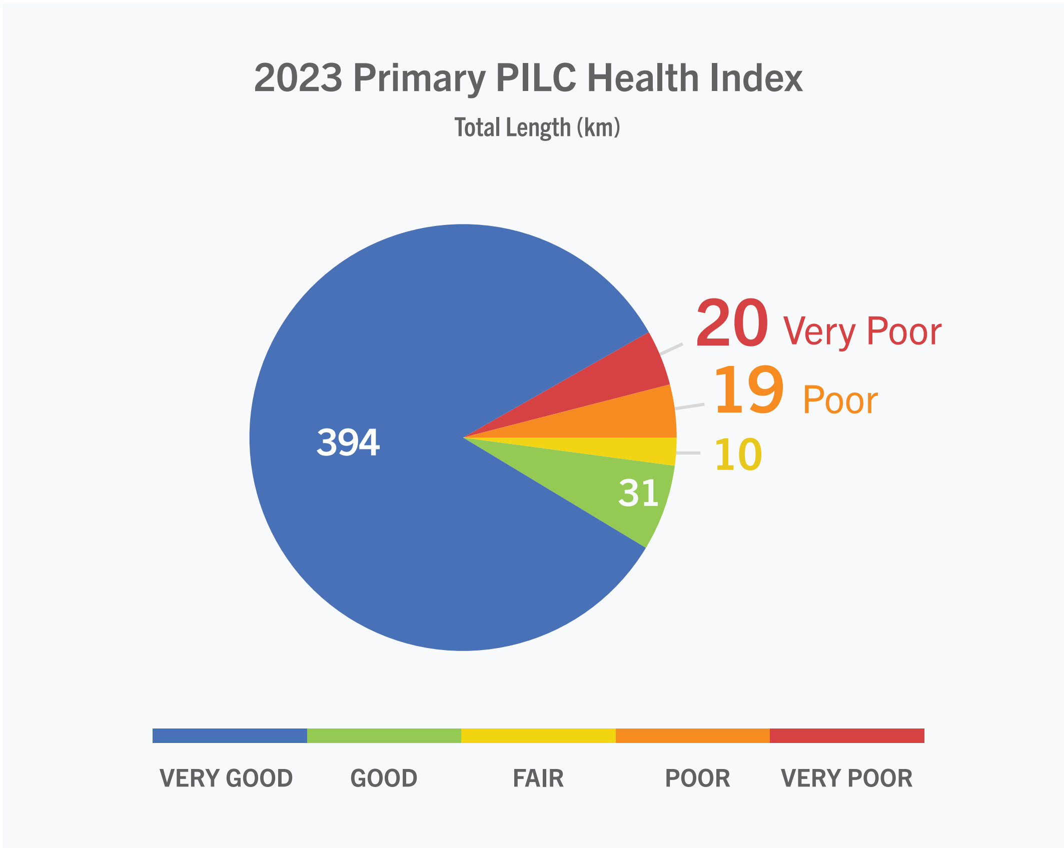


Figure 5.3.2 - 60 PILC Cable Health Index

Asset sustainment practices for PILC cable are detailed in *Chapter 5.3.3 (Section 5.3.3.3 A.6.1)*.

A.1.6.2 EPR Cable

EPR cables represent the smallest population of underground primary cables in Alectra Utilities' system, with less than 1% of the total population. Despite a higher cost relative to XLPE, EPR insulation offers superior flexibility and smaller diameter than equivalent XLPE cable. Alectra Utilities' practice is to use EPR cables as replacement for failed PILC cables. Due to the smaller diameter, three EPR cables can be bundled together and fit within existing 3.5-inch ducts.

Alectra Utilities' distribution system has 114KM of primary underground EPR cable. A breakdown of the age distribution is illustrated in Figure 5.3.2 - 61. Utilities' population of EPR cables is relatively new, with none exceeding 15 years in age. No EPR cable exceeds the TUL.

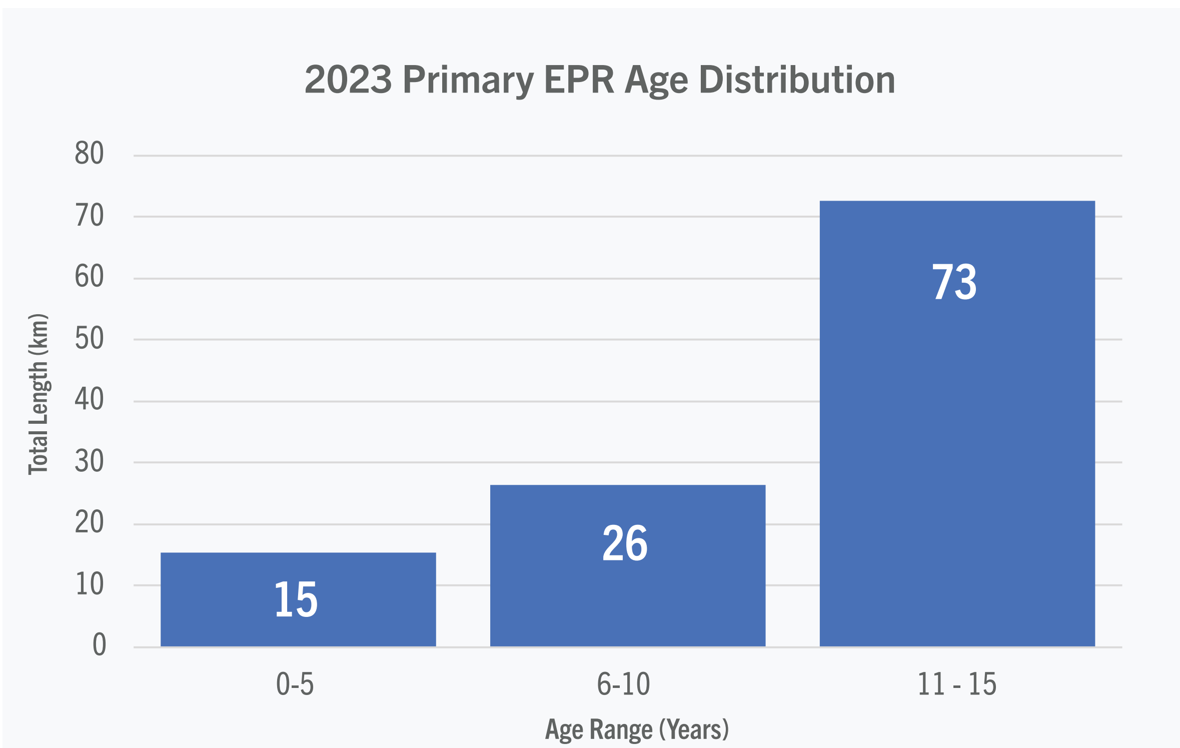


Figure 5.3.2 - 61 Primary EPR Cable Age Distribution

As illustrated in Figure 5.3.2 - 62, all in-service EPR cables are categorized under a “Very Good” Health Index.

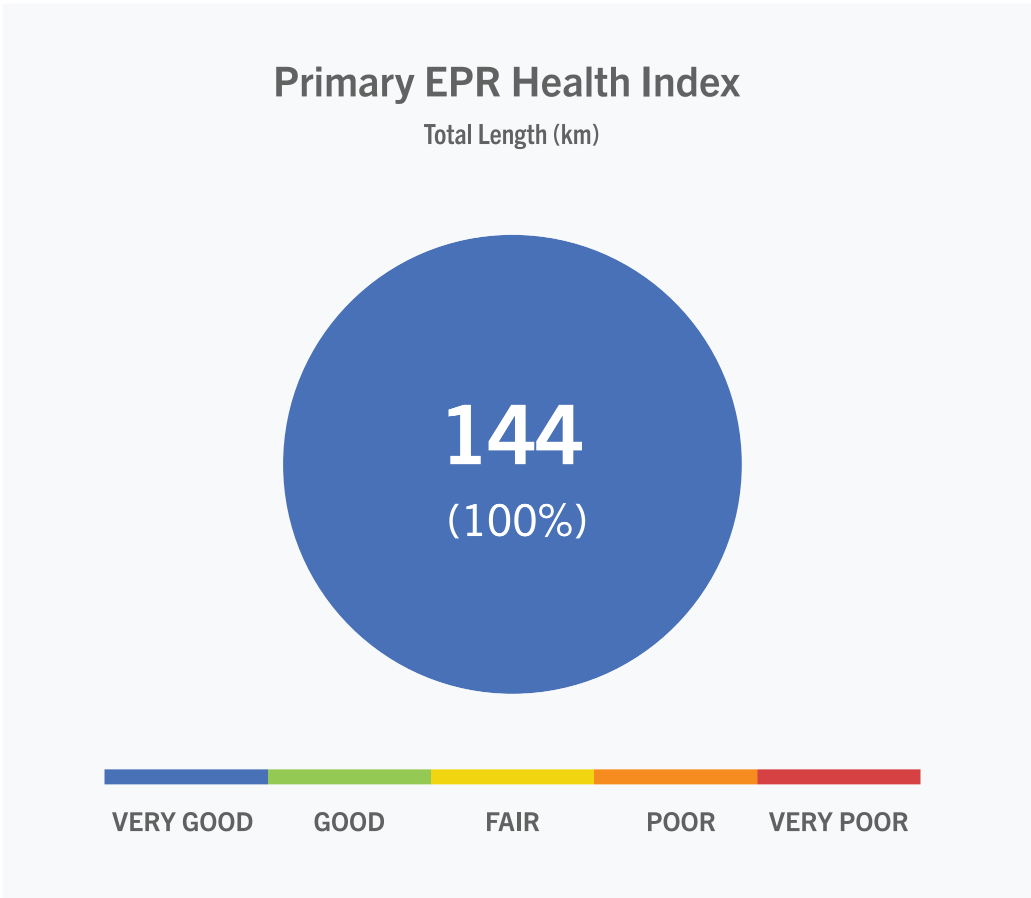


Figure 5.3.2 - 62 EPR Cable Health Index

Long term degradation of EPR cables can occur due to mechanical damage, overheating, or the impact of moisture ingress and chemical deterioration. Asset sustainment practices for EPR cable are detailed in *Chapter 5.3.3 (Section 5.3.3.3 A 1.6.2)*.

A.1.6.3 XLPE Cable

Cross-linked polyethylene (XLPE) cable represents over 97% of Alectra Utilities' primary cable population. Alectra Utilities' distribution system has 23,106KM of primary underground XLPE cable. XLPE cables are categorized by type, as described below. Each type has a different expected useful life, based on industry averages and Alectra's experience.

- **Non-Tree-Retardant cables (NON-TR)**:
    - Vintage 1988 or older; TUL 30 years; EUL 40 years
- **Tree-Retardant Direct-Buried cables (TR-DB)**:
    - Vintage 1989-1993; TUL 35 years; EUL 45 years
- **Tree-Retardant or Strand-Blocked In-Duct cables (TR-ID):**
    - Vintage 1994 or newer; TUL 40 years; EUL 55 years

A breakdown of the age distribution is illustrated in Figure 5.3.2 - 63. A total of 6,651KM of all XLPE cables exceed the TUL, of which 2,375KM exceed the EUL, representing 28.8% and 10.3%, respectively, of the total installed population. The majority of these aging cables are Non-Tree-Retardant type.

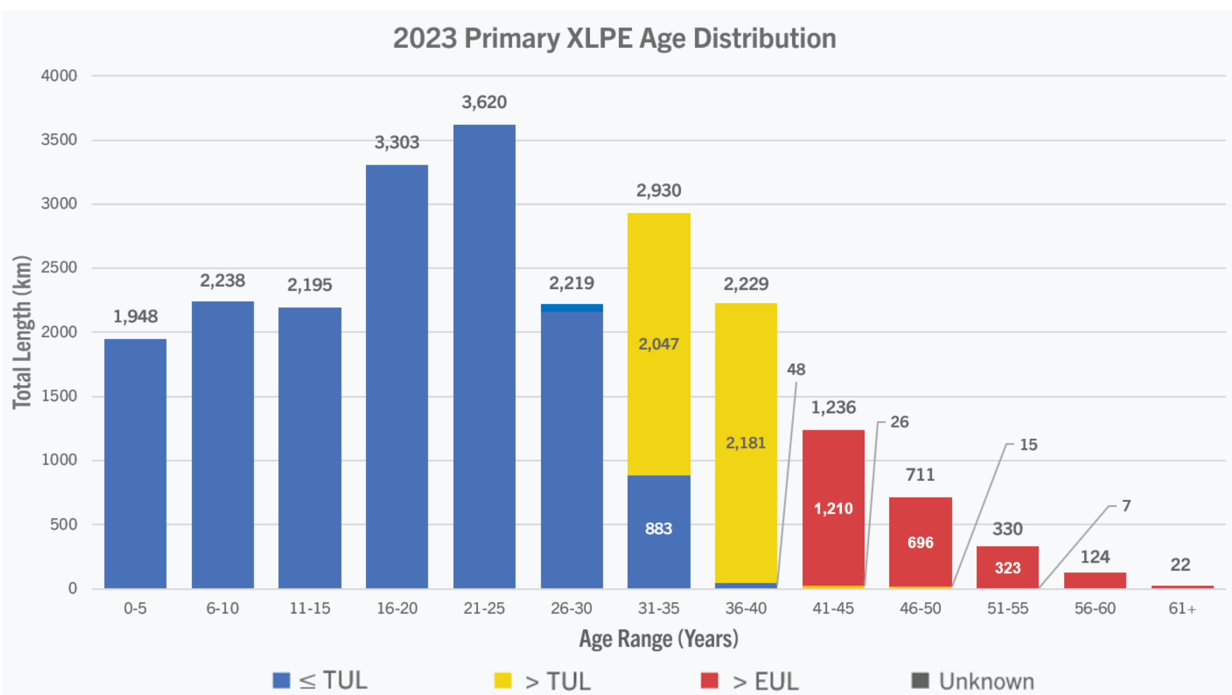


Figure 5.3.2 - 63 Primary XLPE Cables Age Distribution

The first-generation XLPE cables were constructed with stranded or solid conductors and were introduced into the market in the late 1960s. These cables are susceptible to moisture ingress (e.g. water treeing), especially if installed direct-buried where splices are susceptible to insulation breakdown, resulting in localized failures. Older-vintage XLPE cables have inherent problems due to the technology and capability of the manufacturing processes available at the time, which led to the ingress of impurities into the insulating medium. These impurities can become triggers for the creation of water trees (e.g. small conductive paths in the insulation), which eventually become electrical trees. This issue has manifested itself in insulation failures, resulting in faults on primary underground cables. The susceptibility of these cables to water and electrical treeing ultimately contributes to the partial discharge and eventual failure of the cable. As such, legacy XLPE cables introduce significant reliability concerns for Alectra Utilities.

Compounding the issue is that these first-generation cables were originally installed in excavated trenches on a direct-buried basis, with little or no separation between cables, and without any additional mechanical protection that would be offered by a ducted installation. For this reason, these cables are difficult to replace or repair when they fail. Unlike failed cables installed in ducts, which typically can be entirely removed and replaced with brand new cable segments, failed direct-buried cables can only be excavated and repaired via cable splicing in a reactive situation. Such cable splices may introduce a potential failure point.

Manufacturing improvements and the development of tree-retardant XLPE cables in the late 1980s reduced the rate of insulation deterioration due to treeing effects. However, while tree-retardant cables are expected to last longer than their first-generation counterpart, the installation standards used at the time had yet to improve, as these cables were also direct buried and therefore similarly exposed to environmental factors. Further improvements in cable manufacturing in the early 1990s led to the development of strand-blocked XLPE cables, which are no longer susceptible to moisture ingress into the conductor. In addition, Alectra Utilities began installing primary underground cables in ducts in the early 1990s. As such, the life of the tree-retardant or strand-blocked in-duct cable is expected to be longer than the tree-retardant direct buried cables.

The 2023 ACA identified 5,114KM of cables with a “Poor” or “Very Poor” Health Index categorization, as illustrated in Figure 5.3.2 - 64. The need is substantial, and Alectra Utilities is proposing to replace 381KM (i.e. less than 8% of the cables in “Poor” or “Very Poor”) for various reasons detailed in *Appendix B02 – Underground Asset Renewal*.

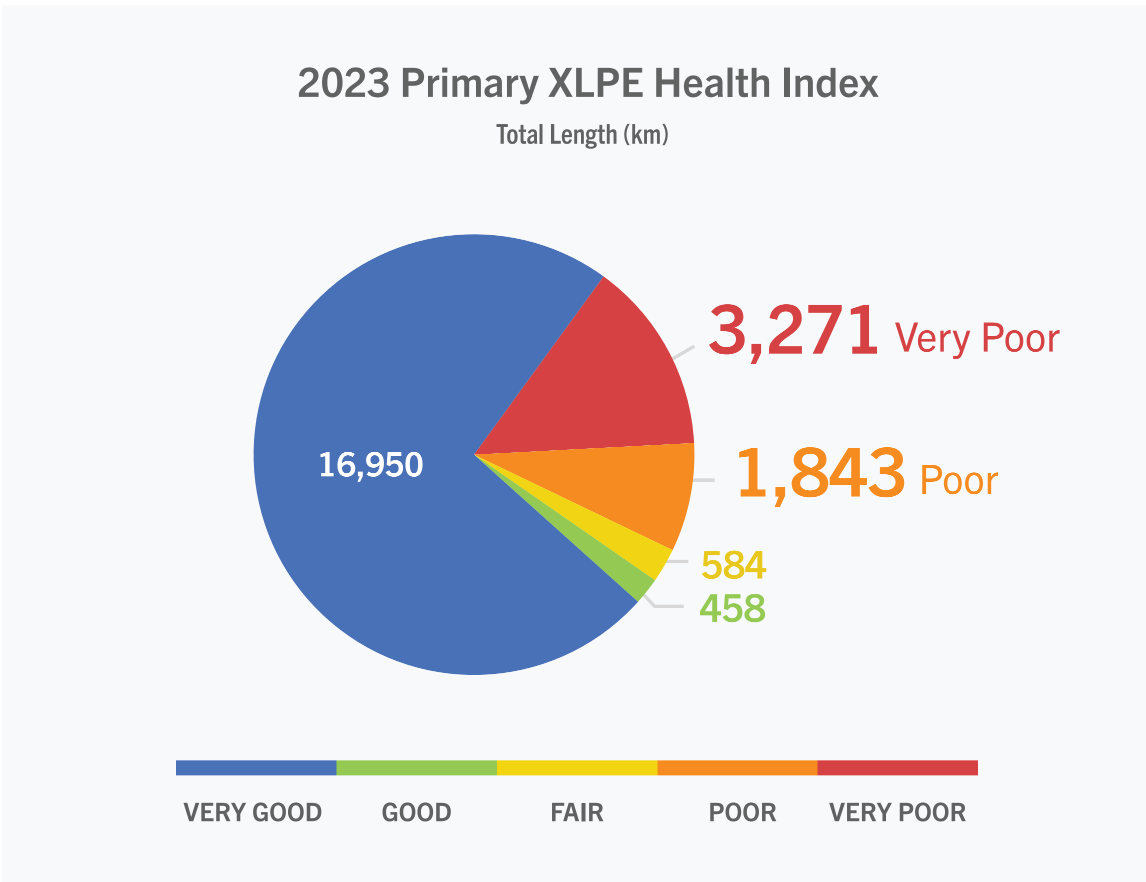


Figure 5.3.2 - 64 XLPE Cable Health Index

Figure 5.3.2 - 65 illustrates the HI distribution of XLPE cables, demonstrating a direct correlation between cable age and condition. The continuous impending wave of aging and deteriorating XLPE cable, if not proactively addressed, will pose a significant reliability risk for Alectra Utilities' system and customers (refer to *Appendix B02 - Underground Renewal* for details on Alectra Utilities' proposed approach to target specific age brackets for cable investment).

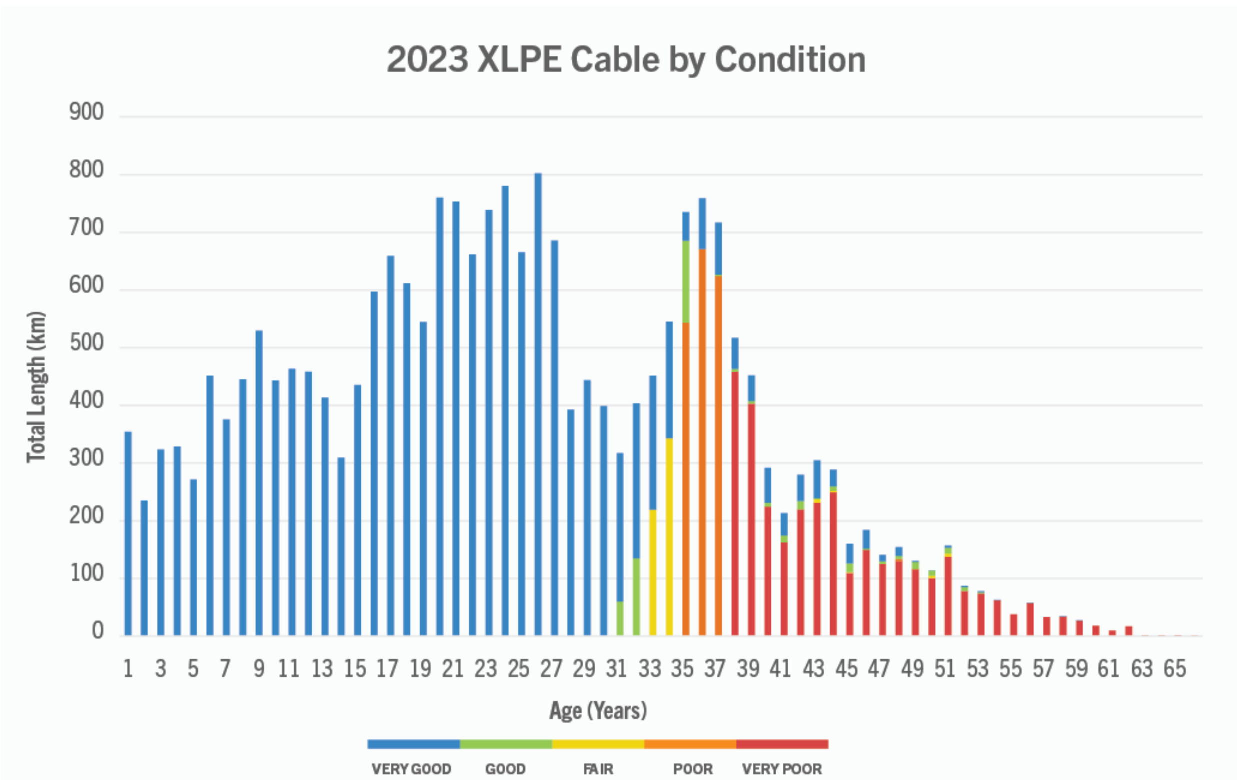


Figure 5.3.2 - 65 2023 XLPE Cable by Condition

To illustrate the elevated failure risk associated with the increase of deteriorated cable, Figure 5.3.2 - 66, Figure 5.3.2 - 67 and Figure 5.3.2 - 68 display the HI results geographically in Mississauga, Markham, and Vaughan, respectively.

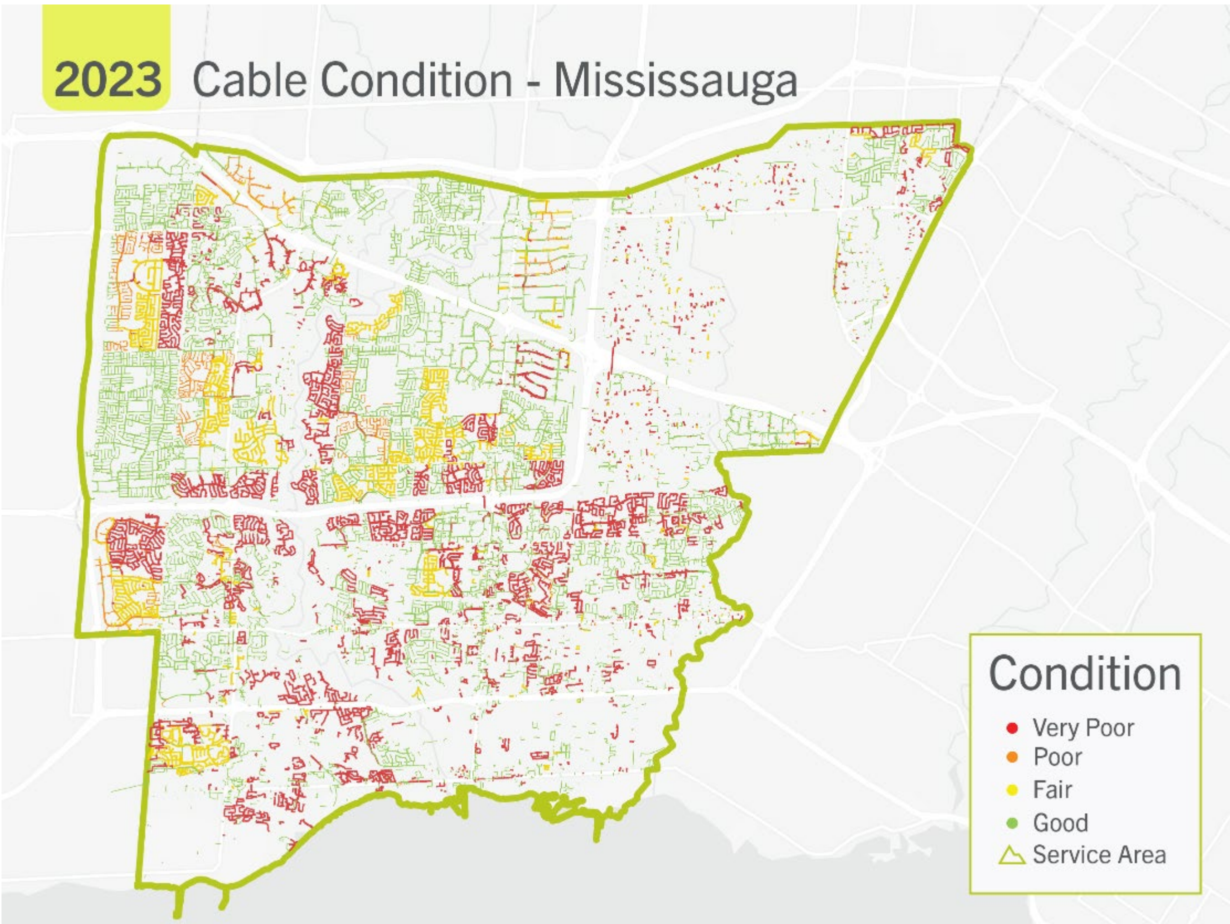


Figure 5.3.2 - 66 Mississauga – XLPE Cable Health Index

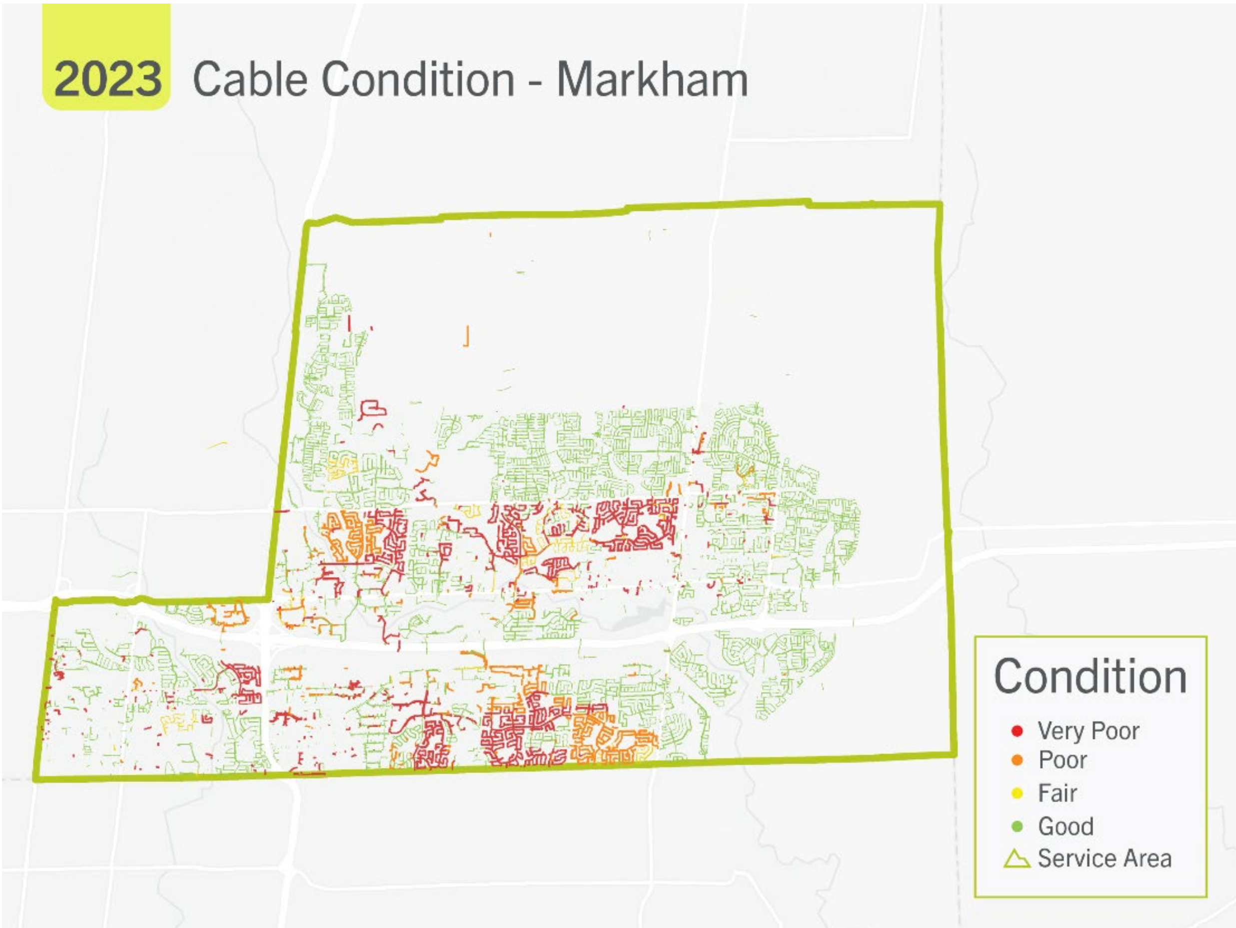


Figure 5.3.2 - 67 Markham – XLPE Cable Health Index

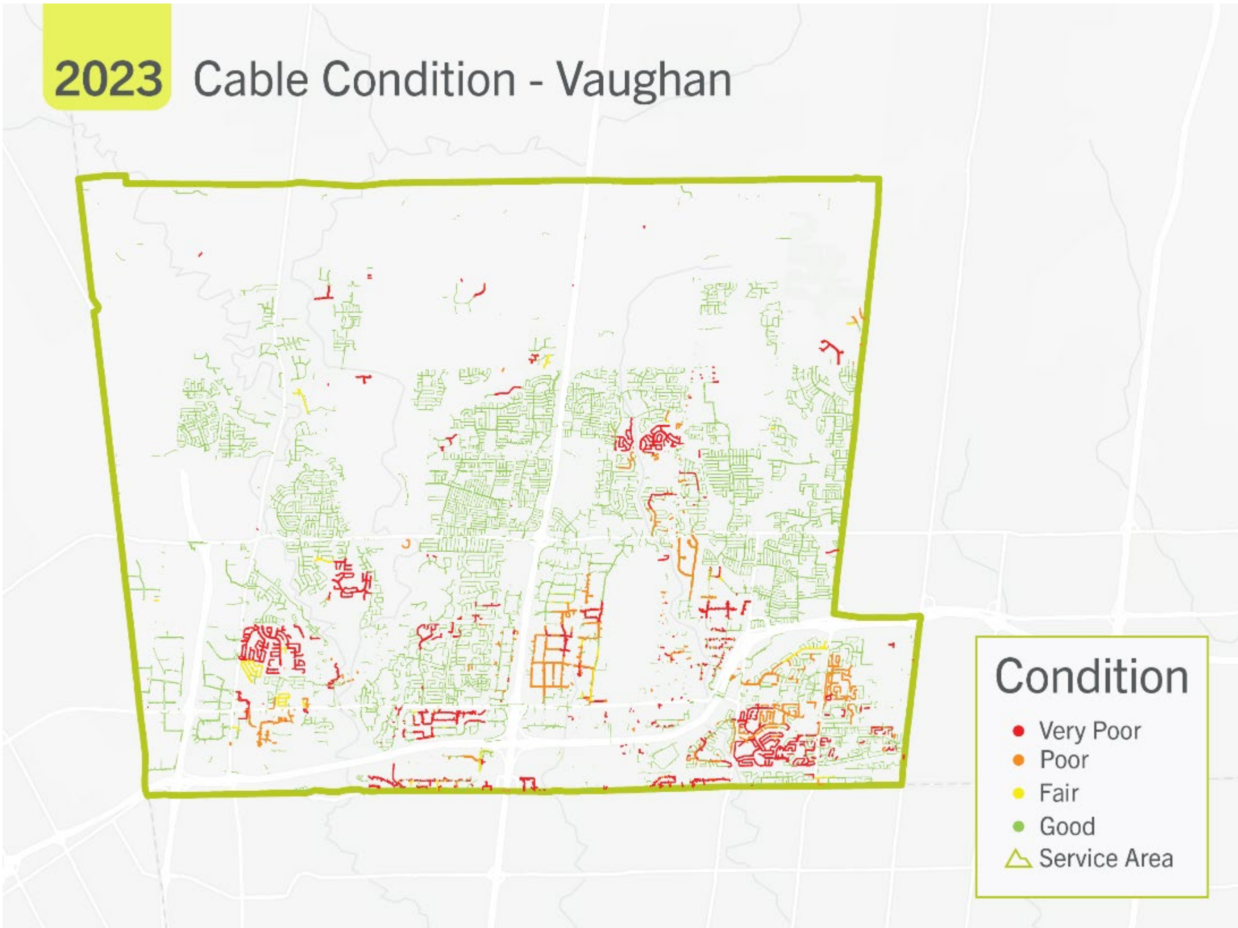


Figure 5.3.2 - 68 Vaughan – XLPE Cable Health Index

Cable faults are increasing in complexity, with faults occurring in areas that are difficult for crews to reach to make necessary repairs. Several neighbourhoods within Alectra Utilities service area have already experienced disruption patterns consistent with the progressive degradation of aging XLPE cable. In the Sir John's Homestead subdivision in Mississauga, 18 cable faults occurred between 2005 and 2021, with fault frequency accelerating in the three years leading up to full rebuild in 2022. One segment experienced five separate failures, and multiple outages occurred within the same month, prompting customer complaints. A comparable pattern was observed along Valleywood Drive in Markham. Following a relatively low fault history between 2018 and 2023, the area experienced seven cable faults within a three-month span in 2024. Extended outages up to 41 hours led to formal complaints. Previous attempts at isolated replacements were insufficient in preventing further failures. The area was fully rebuilt in 2024.

These cases highlight a pattern in which each cable fault contributes to the deterioration of nearby segments, leading to more frequent and severe outages over time. If left unmitigated, such conditions typically necessitate more frequent reactive interventions. Accordingly, planned replacement of aging XLPE cable is critical to interrupt escalating failure events and to maintain distribution system reliability. Without intervention, this often leads to reactive rebuilds under worsening conditions. Proactively replacing aging XLPE cable is therefore necessary to break this cycle and maintain reliable service for customers.

Figure 5.3.2 - 69 illustrates an increasing trend of the “Poor” and “Very Poor” XLPE cable population. It also illustrates cables that were proactively replaced from 2018 to 2023, suggesting that the current rate of replacement is not sufficient to address an increasing backlog of deteriorated cable. As further detailed in *Appendix B02 – Underground Renewal*, the population of “Poor” and “Very Poor” cables is projected to steadily increase between the years 2024 and 2031 despite ongoing investment in cable injections. With injection candidates diminishing by the end of 2029, Alectra Utilities will transition its focus towards cable replacement to address the accelerating rate of cable deterioration and enhance long-term system reliability.

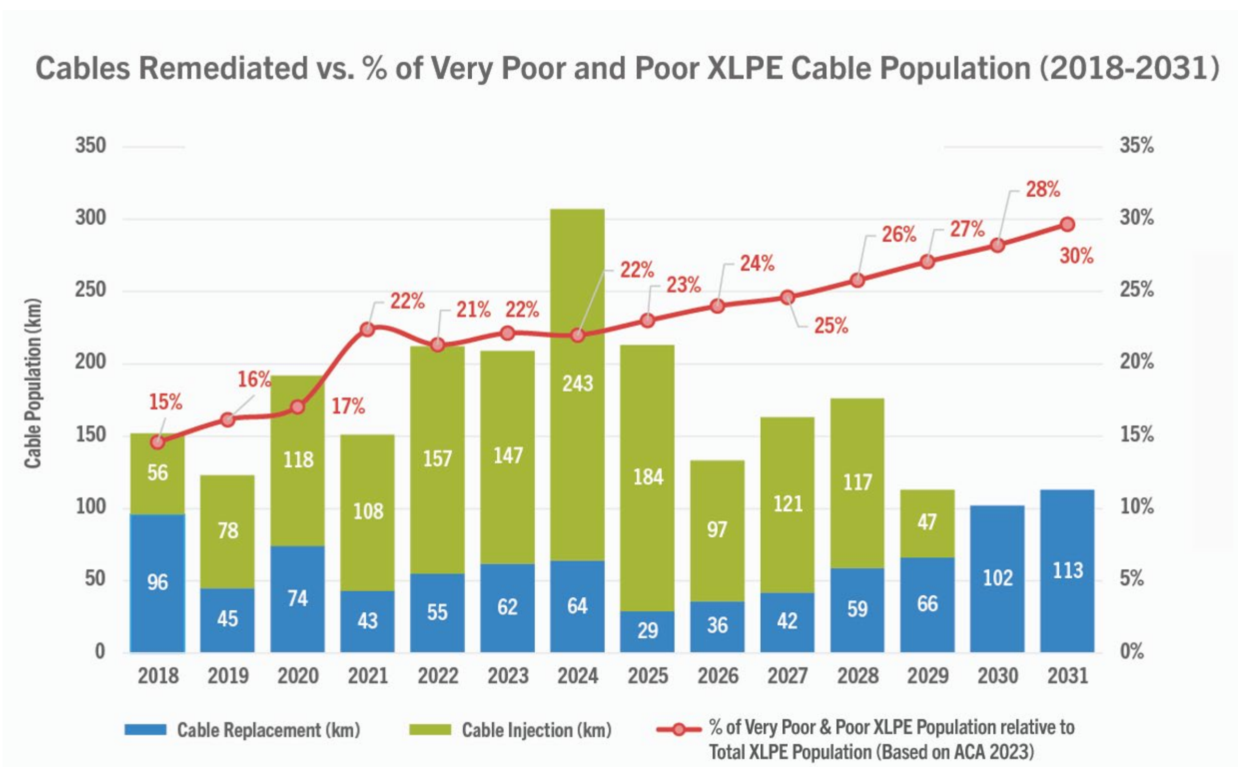


Figure 5.3.2 - 69 Cables Remediated vs. % of Very Poor and Poor XLPE Cable Population (2018 to 2031)

Figure 5.3.2 - 70 illustrates the significance of XLPE cable failures on customer outages compared to all equipment-related failures.

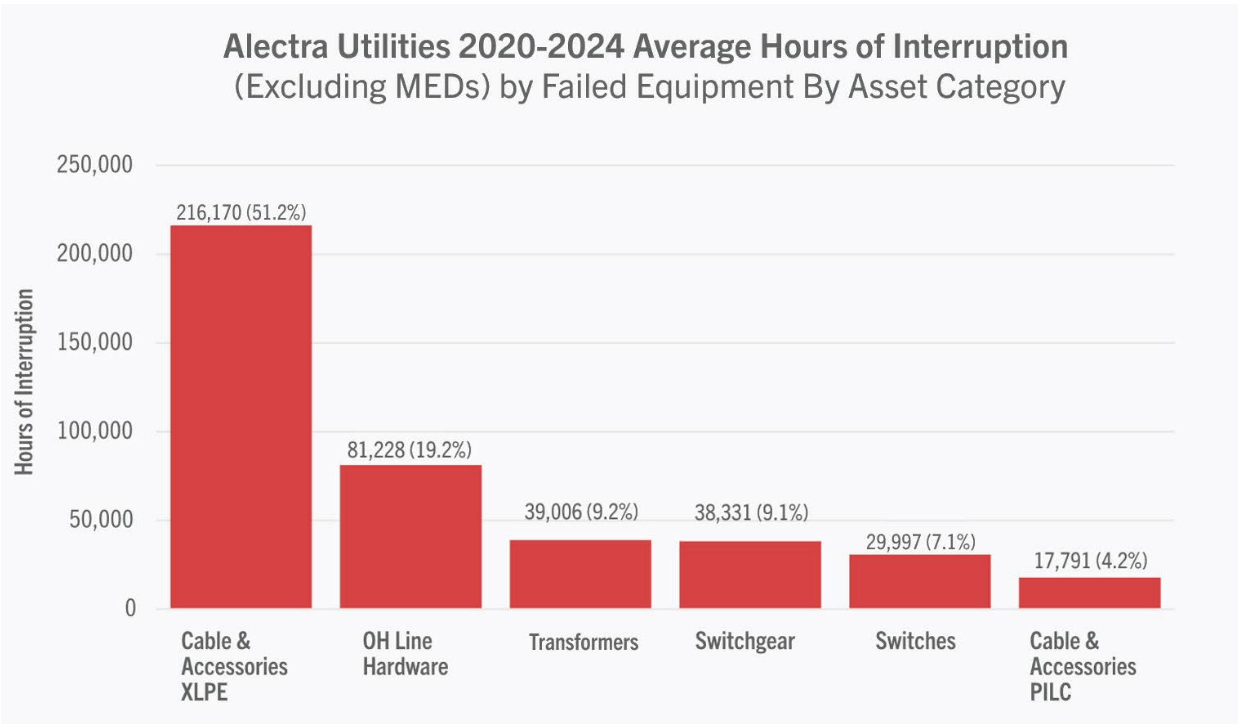


Figure 5.3.2 - 70 2020-2024 Sub-Causes of Defective Equipment

Failure of XLPE cable and accessories continues to be the highest contributor to customer hours of interruption (CHI). This reflects the volume and vintage of XLPE cable currently in service in Alectra Utilities service area.

Compared to the 2014-2018 average CHI of 202,003, the 2019-2024 average CHI has increased by 7% for XLPE cable and accessories. Alectra Utilities identifies XLPE failure risk as its investment priority. Alectra Utilities has attempted to address the increasing failure trends associated with XLPE cable through its existing funding levels. Failing direct-buried cables are resulting in prolonged restoration efforts and significantly impact the quality of service received by Alectra Utilities' customers. Figure 5.3.2 - 71 provided below highlights the fact that with OEB approval through two ICM applications, in conjunction with targeted investments, Alectra Utilities was able to reduce the cable outages from 2018 levels despite the increased deterioration. The above highlights the fact that cable remediation projects have had a net positive impact and with additional funding Alectra Utilities expects to continue to mitigate the risks associated with cable failures and ultimately provide customers with the supply that they need and expect.

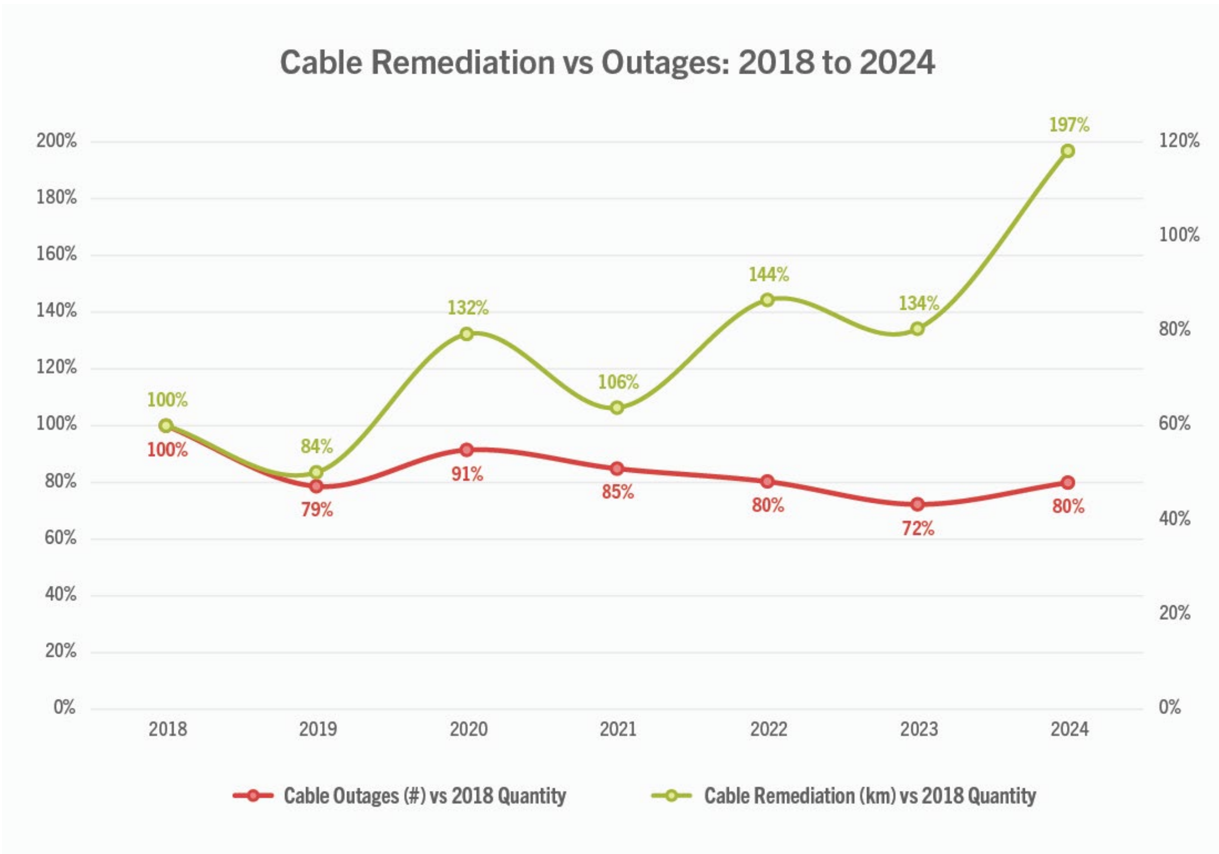


Figure 5.3.2 - 71 Cable Remediation Quantity vs. Outages, in Percentage (2018 to 2024)

Managing the failure risk associated with XLPE cable is Alectra Utilities' most pressing investment need based on reliability impact. To this end, during the 2027-2031 DSP period, Alectra Utilities plans to gradually and significantly increase its investment to rehabilitate[6] or replace XLPE cables and related accessories that are either in "Poor" or "Very "Poor condition"[7]. Asset sustainment practices for XLPE cable are further detailed in *Chapter 5.3.3 (Section 5.3.3.2 A.6.3)*. Investment options for XLPE cable are discussed in *Appendix B02 - Underground Renewal*.

[6] Cable injection will end in 2029 due to low quantity of feasible candidates

[7] Underground assets targeted for renewal have Very Poor or Poor HI scores. Detailed information on Alectra Utilities' ACA process is provided in *Appendix E 2023 Asset Condition Assessment (ACA)*

A.2 Station Assets

Alectra Utilities' station infrastructure is critical to the transformation of high voltage supply from the bulk transmission system to the distribution system. Station asset failure can lead to lengthy interruptions to many customers. Alectra Utilities owns and operates 14 Transformer Stations and 149 Municipal Stations. The TSs are supplied from the HONI high-voltage transmission grid at 115kV or 230kV, while the MSs are supplied from the low side of HONI or Alectra Utilities' TSs at 44kV, 27.6kV, or 13.8kV.

Table 5.3.2 - 10 summarizes the asset inventory of major station assets, by Operating Area. An ACA is conducted for all power transformers, circuit breakers, and station switchgear. Alectra Utilities' assessment of station assets also covers primary switches, station protection relays, station service transformers, and other ancillary equipment. These assessments rely on the findings from stations inspection and maintenance activities.

Table 5.3.2 - 10 Asset Inventory (Station Assets)

Asset Category	Operating Area				
	Central	East	West	Southwest	Total
Transformer Stations	1	12	0	1	14
Municipal Stations	76	54	17	2	149
All Stations	77	66	17	3	163
TS Transformers (including spares)	3	26	0	2	31
MS Transformers (including spares)	135	75	46	2	258
All Transformers	138	101	46	4	289
TS Circuit Breakers & Reclosers	22	196	0	18	236
MS Circuit Breakers & Reclosers	584	220	229	8	1041
ALL Circuit Breakers & Reclosers	606	416	229	26	1277
TS Switchgear	2	19	0	1	22
MS Switchgear	241	60	40	2	343
All Station Switchgear	243	79	40	3	365
High-voltage Primary Switches (Sets of 3)	2	24	0	4	30
TS Station Capacitors	0	11	0	0	11
TS HV PMU ITs[8]	7	36	0	0	43
TS Station Service Transformers	2	20	0	2	24
TS P&C Relays (Microprocessor)	32	261	0	18	311

[8] High-voltage primary metering unit instrument transformers

Asset Category	Operating Area				
	Central	East	West	Southwest	Total
TS P&C Relays (Solid State)	0	22	0	0	22
TS P&C Relays (Electromechanical)	0	20	0	0	20
All TS P&C Relays	32	303	0	18	353
MS P&C Relays (Microprocessor)	383	241	133	8	765
MS P&C Relays (Solid State)	256	3	0	0	259
MS P&C Relays (Electromechanical)	205	1	55	0	261
All MS P&C Relays	844	245	188	8	1285
All Protection & Control (P&C) Relays	876	548	188	26	1638

1 Table 5.3.2 - 11 summarizes typical failure modes and associated impacts for each station asset
2 type considered in the ACA as well as for protection relays.

3 **Table 5.3.2 - 11 Typical Asset Failure Modes and Impacts (Station Assets)**

Asset	Typical Failure Modes	Impacts
Station Power Transformers	• Bushing failure due to moisture ingress, aging, improper construction, and lightning • Defective gasket in oil-filled bushing • Oil leaks from failing transformer gaskets • Paper insulation failure • Defective breather (all possible causes) • Control circuit or motor failure of onload tap changer • Overloading and/or failure of transformer cooling	• Explosive failure, resulting in a station outage and possible damage to adjacent equipment from porcelain projectiles • Oil leaks, leading to loss of insulation, a short-circuit, and eventually a station outage • Moisture ingress, resulting in insulation breakdown, leading to premature failure and a station outage, and oil loss leading to exposure of uninsulated portions of the active transformer components, resulting in flashovers and a station outage • Low or fluctuating voltage or internal fault leading to transformer failure and station power outage • Moisture ingress leading to decreasing insulation value of the oil and eventually causing oil dielectric breakdown causing a flashover • Improper transformer secondary voltages, resulting in over or undervoltage situations, risking reduced efficiency or malfunctioning of connected equipment • Degradation of the cellulose insulation, leading to premature transformer failure and a station outage

Asset	Typical Failure Modes	Impacts
Station Circuit Breakers	• Breaker fails to open to clear fault (all causes) • Worn latching mechanism, broken lifting rod, or failed linkage • Bushing failure • Loss of insulating medium • Interrupting medium/ component failure	• Power outage to the entire station bus • Operating mechanism fails to close the breaker, resulting in continued customer supply interruption until transferred to an • alternate supply • Flashover causing damage to the breaker and customer supply interruption • Failure to trip or failure to clear the fault or extinguish the arc, resulting in equipment damage and loss of the station bus
Station Switchgear	• Loose control cable connection • Broken/cracked interphase barrier or insulators, dirt or debris on insulators • Total cable failure (all possible causes) • Dirt or debris on busbar conductors.	• Loss of ability to monitor and operate the breaker via protection and control, resulting in an arc flash • Possible flashover, and safety issue involved with the failure due to the explosion if the protection fails • Loss of power due to relay protection sensing the cable fault and tripping the breaker • Partial discharge, overheating and melting of the busbar, leading to flashovers that can cause bus failure and result in an extended station outage
Protection Relays	• Electromechanical: a. Contact deterioration (contact welding, corrosion, pitting) b. Spring fatigue c. Relay coil deterioration • Solid State: a. Power supply malfunction b. Electronic component (including semiconductors, capacitors) degradation • Microprocessor:	• Relay deterioration can result in slow operation or failure to operate, thereby not clearing faults as intended and prolonging fault conditions. Impacts include risk of equipment damage, safety hazards, service interruptions, and system instability.

Asset	Typical Failure Modes	Impacts
	a. Power supply malfunction b. Electronic components (including integrated circuits) degradation c. Software or firmware issues d. Communication networks disruptions	

The ACA relies on the findings from the station inspection, testing, and maintenance activities detailed in *Chapter 5.3.3 Asset Lifecycle Optimization Policies and Practices*.

A.2.1 Power Transformers

Station power transformers are used to step down transmission or sub-transmission voltage to distribution voltage levels. The two general classifications of station power transformers are TS transformers and MS transformers. TS transformers are supplied from the high-voltage transmission grid at either 230kV or 115kV and step voltage down to 44kV, 27.6kV, or 13.8kV. MS transformers are supplied from the medium-voltage distribution system at 44kV, 27.6kV, or 13.8kV, and step voltage down to 27.6kV, 13.8kV, 8.32kV, or 4.16kV. TS transformers owned and operated by Alectra Utilities have fully-cooled ratings of 50MVA, 83.3MVA, and 125MVA, and MS transformer ratings typically have base Oil Natural Air Natural (ONAN) ratings ranging from 3MVA to 22MVA.

Power transformers employ many different design configurations, but they are typically made up of the following main components: primary and secondary windings, laminated iron core, internal insulating mediums, main tank, bushings, cooling system (including radiators, fans and pumps, where applicable), off-load tap changer (optional), on-load tap changer (optional), instrument transformers, control mechanism cabinets, and instruments and gauges.

Alectra Utilities has 289 power transformers. These are comprised of 31 TS transformers, three of which are spares, and 258 MS transformers, which include 24 spares and units undergoing refurbishment.

Figure 5.3.2 - 72 illustrates the age distribution of power transformers. A total of 49 transformers exceed the TUL of 45 years, of which four exceed the EUL of 60 years, representing 17% and 1.4%, respectively, of the total population. All 49 of these transformers are at municipal stations.

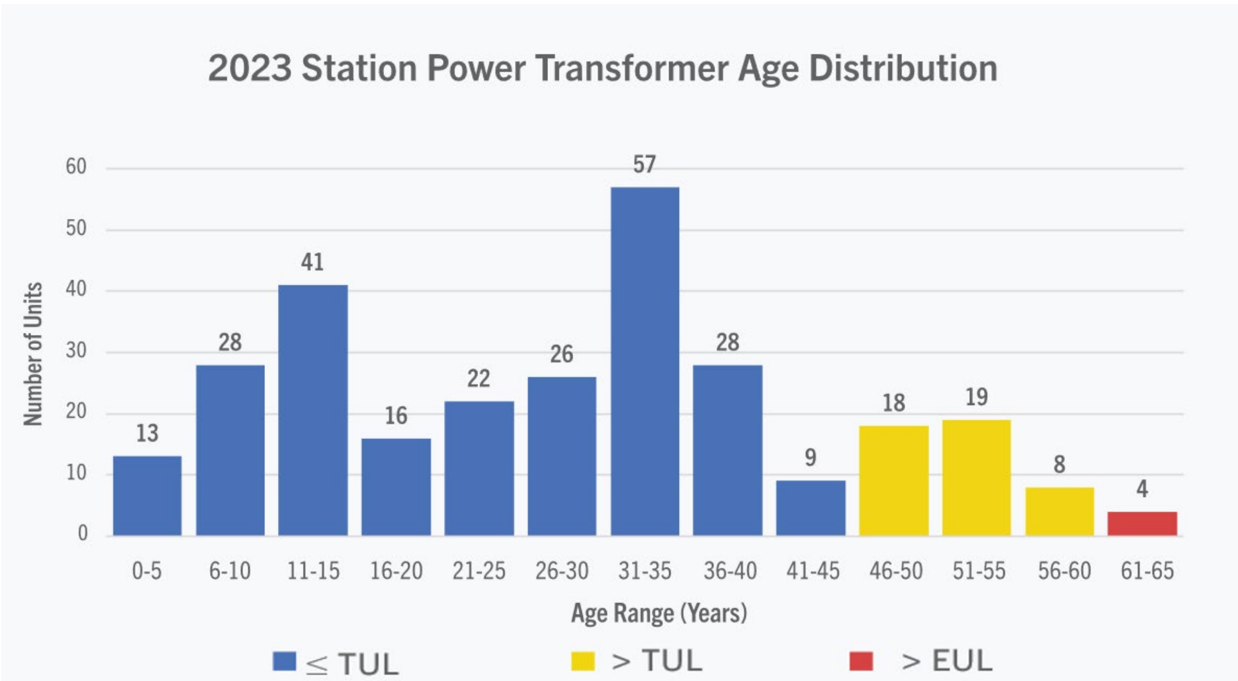


Figure 5.3.2 - 72 Power Transformers Age Distribution

The Health Index for power transformers is computed by adding the weighted scores of their condition factors which include oil quality and dissolved gas analysis test results and visual inspection details. Given the availability of direct condition data, age is not factored into the Health Index calculation.

Figure 5.3.2 - 73 illustrates the power transformer HI distribution by condition category. Twelve power transformers are in the "Very Poor" or "Poor" condition category. All 12 are MS transformers.

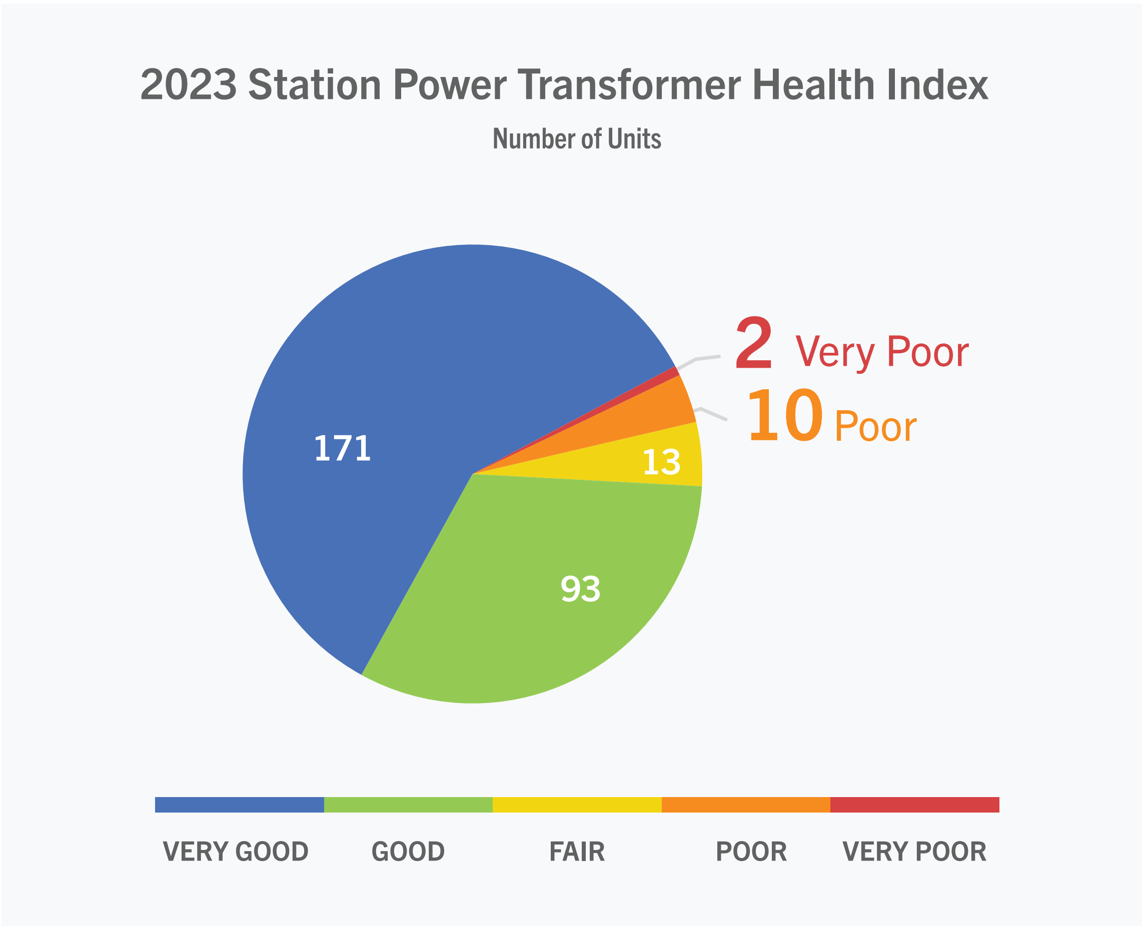


Figure 5.3.2 - 73 Power Transformer Health Index

Figure 5.3.2 - 74 shows an MS power transformer experiencing an oil leak. Oil leaks are a sign of failing gaskets which can lead to moisture ingress, ultimately resulting in insulation breakdown and premature transformer failure.

Figure 5.3.2 - 74 Power Transformer Experiencing an Oil Leak

Power transformer sustainment practices are detailed in *Chapter 5.3.3 (Section 5.3.3.2 B.1),* replacement practices in *Chapter 5.3.3 (Section 5.3.3.3 B.4)*, and investment strategy in *Appendix B04 - Substation Renewal.*

A.2.2 Circuit Breakers

Circuit breakers are used to sectionalize and isolate circuits or other assets. They are often categorized by the insulation medium used in the circuit breaker and by the fault-current interruption process. The common types include oil circuit breakers, air circuit breakers, vacuum circuit breakers, and SF_6 circuit breakers. Circuit breakers can be enclosed in switchgear or can stand alone.

Alectra Utilities' system has 1,277 installed circuit breakers at its stations, 236 of which are associated with transformer stations.

Figure 5.3.2 - 75 illustrates the age distribution for circuit breakers, both stand-alone and in switchgear. A total of 187 circuit breakers exceed the TUL of 40 years, of which 59 exceed the EUL of 60 years, representing 14.6% and 4.6%, respectively, of the total installed population.

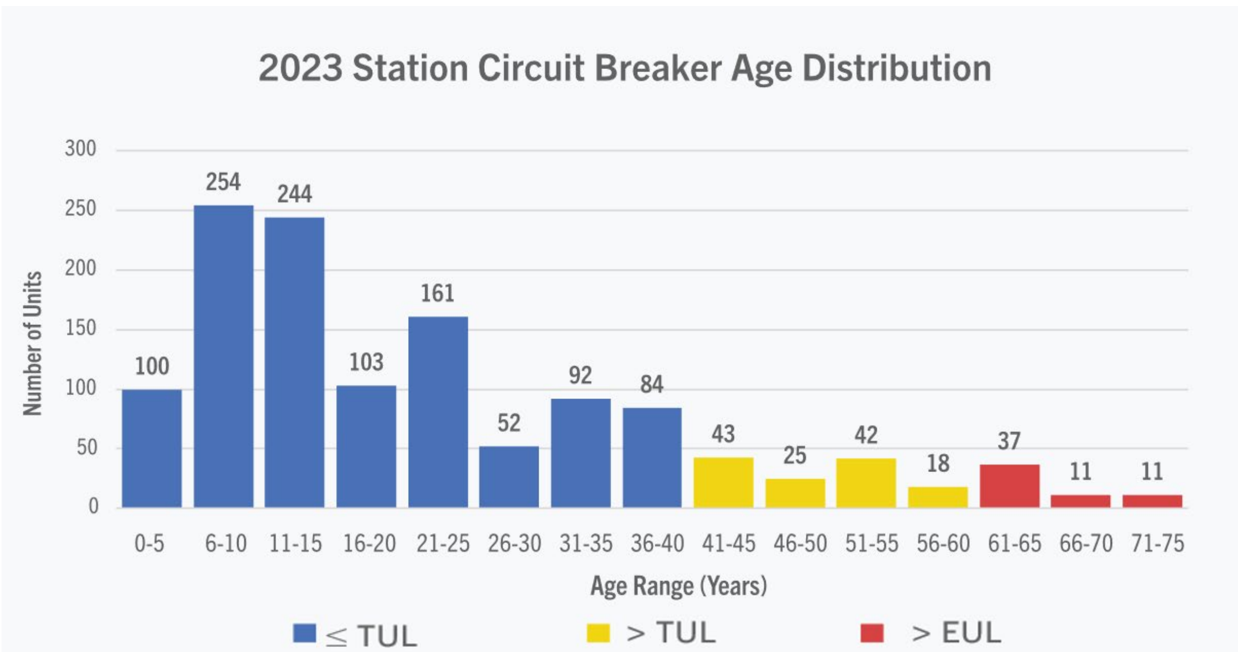


Figure 5.3.2 - 75 Circuit Breakers Age Distribution

The Health Index for circuit breakers is computed by adding the weighted scores of their condition factors which include various test results as well as visual inspection details. Given the availability of direct condition data, age is not factored into the Health Index calculation.

Figure 5.3.2 - 76 illustrates the circuit breaker HI distribution by condition category. The HI data set includes both stand-alone breakers and breakers enclosed in switchgear. As shown, 114 circuit breakers are classified as being in the “Very Poor” or “Poor” condition; all 114 are enclosed in station switchgear.

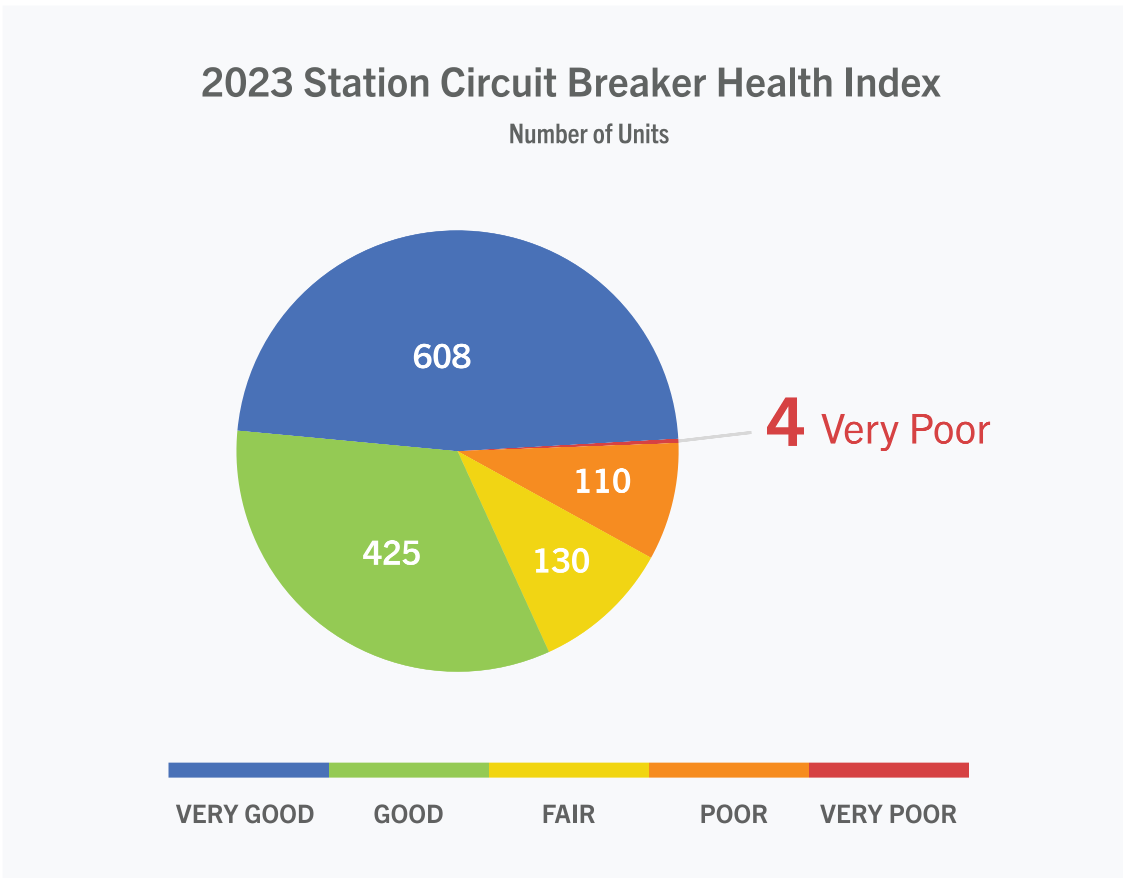


Figure 5.3.2 - 76 Circuit Breaker Health Index

Failure of a circuit breaker to operate can lead to an explosive failure, presenting a serious safety risk and a lengthy and costly service interruption.

Figure 5.3.2 - 77 shows the interior of an outdoor circuit breaker that has since been removed from service. The presence of corrosion and debris can impact breaker operation.

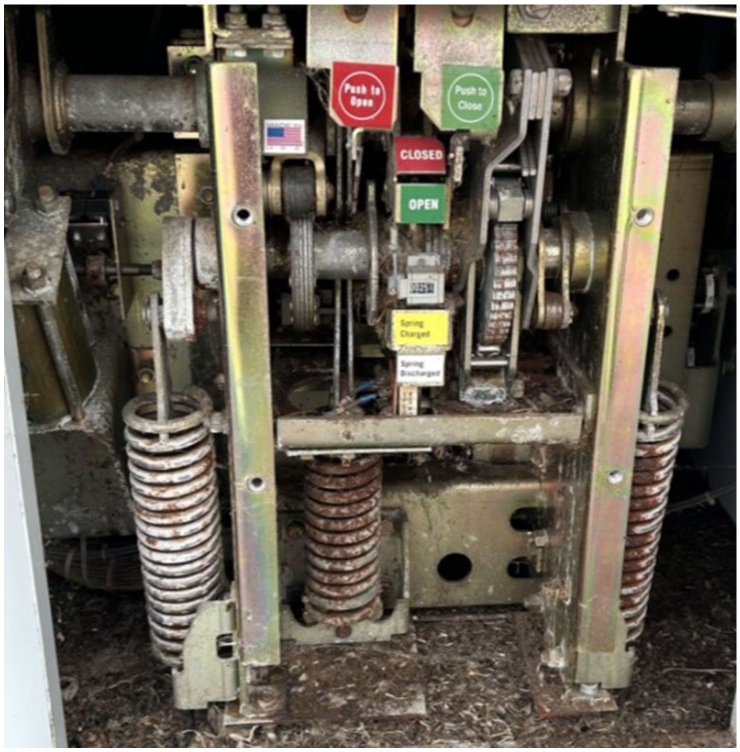


Figure 5.3.2 - 77 Interior of Rusting Outdoor Circuit Breaker

Circuit breaker sustainment practices are detailed in *Chapter 5.3.3 (Section 5.3.3.2 B.2),* replacement practices in *Chapter 5.3.3 (Section 5.3.3.3 B.4)* and investment options in *Appendix B04 - Substation Renewal*.

<u>A.2.3 Station Switchgear</u>

Station switchgear consists of an assembly of retractable/racked devices that are totally enclosed in a metal envelope (metal-enclosed). These devices operate in the medium-voltage range, from 4.16kV to 44kV. Station switchgear includes circuit breakers, disconnect switches or fuse gear, current transformers (CTs), potential transformers (PTs), and occasionally some or all the following: metering, protective relays, internal DC and AC power, battery charger(s), and AC station service transformation. This equipment is modular in that each circuit breaker is enclosed in its own metal envelope (cell). Station switchgear is also compartmentalized, having separate compartments for circuit breakers, control, incoming/outgoing cables or bus duct, and busbars associated with each cell. For calculating station switchgear HI, the enclosed circuit breakers are not included; HI for all breaker types is calculated separately.

Alectra Utilities' system has 365 station switchgear. Figure 5.3.2 - 78 illustrates the age distribution of station switchgear. A total of 93 station switchgear exceed the TUL of 40 years, of which 21 exceed the EUL of 60 years, representing 25.5% and 5.8%, respectively, of the total installed population.

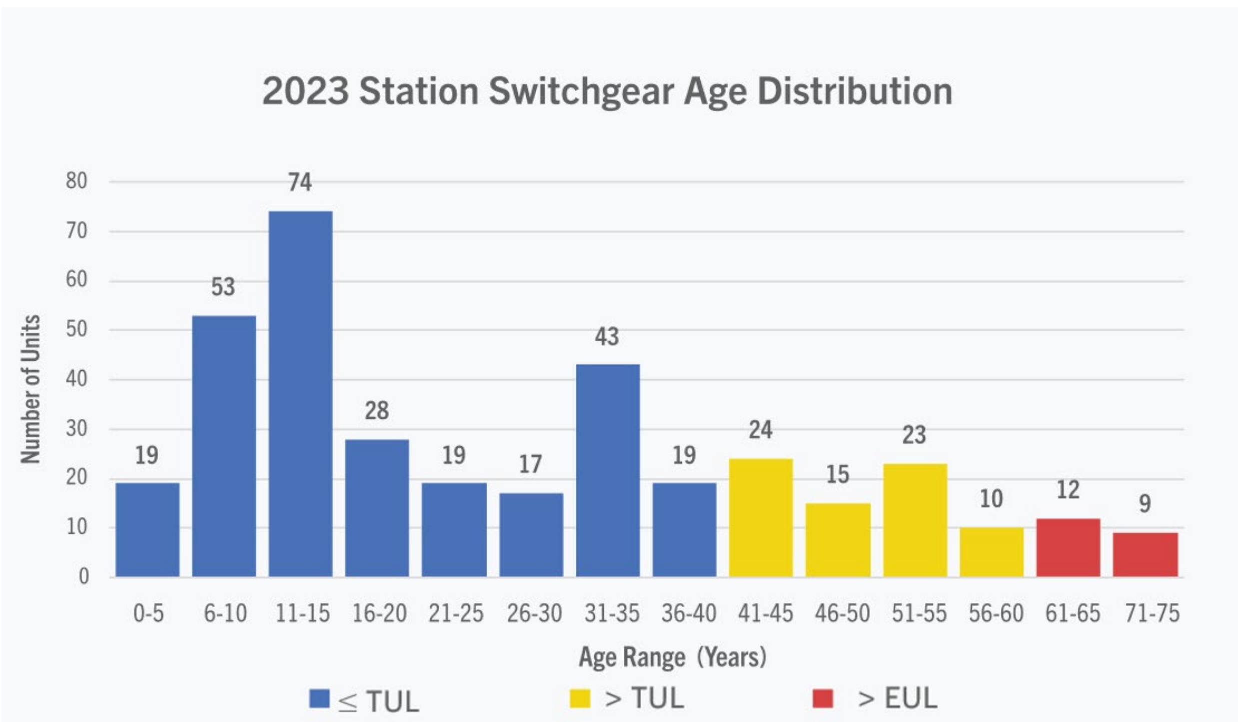


Figure 5.3.2 - 78 Station Switchgear Age Distribution

The Health Index for station switchgear is computed by adding the weighted scores of their condition factors which include various test results as well as visual inspection details. Because several condition factors are available for station switchgear, age is not factored into the Health Index calculation.

Figure 5.3.2 - 79 illustrates the station switchgear HI distribution by condition category. As shown, 39 station switchgear are categorized as being in the “Poor” condition. This compares to 36 station switchgear in the “Poor” category in 2018. This increase occurred despite the replacement of 11 station switchgear over the same period, indicating the ongoing need for replacements to address the rate of asset deterioration.

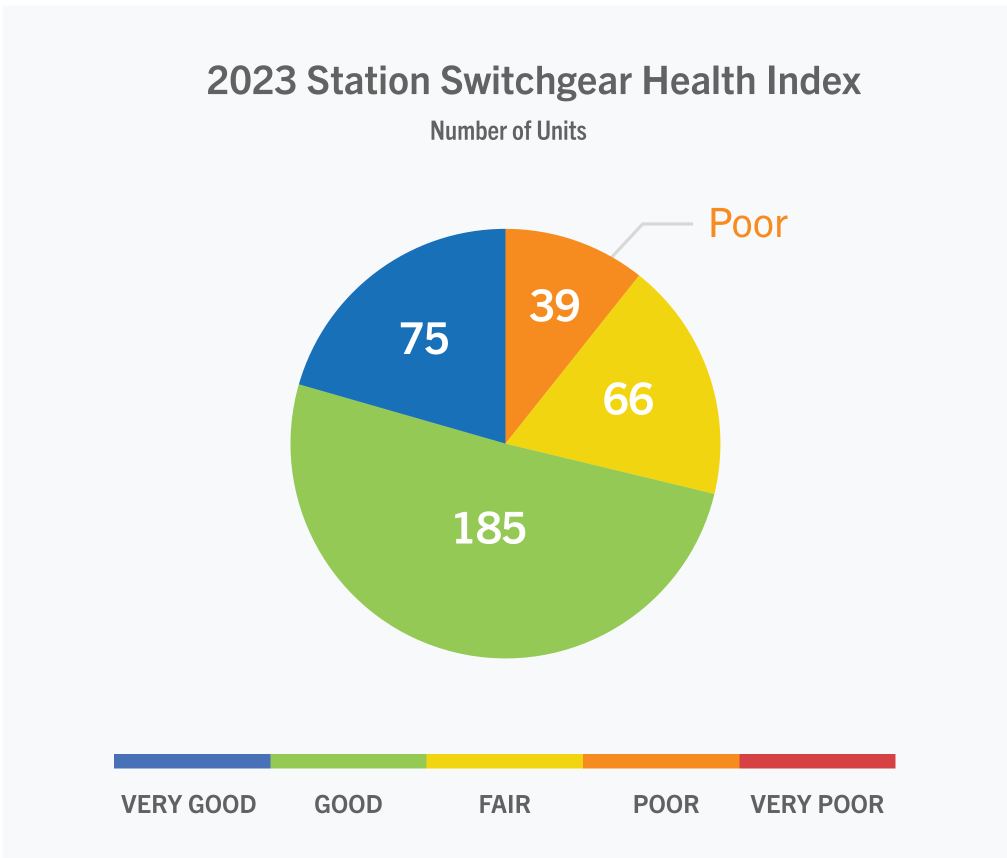


Figure 5.3.2 - 79 Station Switchgear Health Index

Figure 5.3.2 - 80 shows photos of rust inside a station switchgear cabinet. Rust can compromise the switchgear housing, leading to dust and debris ingress and insect and rodent infestation, all of which can result in partial discharge and flashover that can lead to failure.

Figure 5.3.2 - 80 Rust inside a Station Switchgear Cabinet

Station switchgear sustainment practices are detailed in *Chapter 5.3.3 (Section 5.3.3.2 B.3)*, replacement practices *in Chapter 5.3.3 (Section 5.3.3.3 B.4),* and investment strategy in *Appendix B04 - Substation Renewal*.

A.2.4 Protection and Control Systems

The primary function of a protection and control system is to provide monitoring and protection of station equipment and to initiate circuit breaker trip and close functions. This function is extremely important because it protects equipment from being damaged by high electrical currents that flow through electrical equipment during fault conditions. Protection systems operate to clear the fault by opening circuit breakers or other protective devices to cease the flow of fault current before equipment sustains damage.

Alectra Utilities' station protection and control systems include protective relays of three types: Electromechanical, Solid State, and Microprocessor-based. Electromechanical and solid state relays represent older technologies that have basic open-close functionality. Microprocessor-based relays are more modern devices and have enhanced capabilities that include advanced communications and fault recording. Alectra Utilities system has 1,638 station protection relays, comprised of all three types.

Alectra Utilities has 281 electromechanical relays installed at its stations. Figure 5.3.2 - 81 illustrates the age distribution of these relays. A total of 262 relays are shown to exceed the TUL of 35 years, of which 86 exceed the EUL of 50 years, representing 93.2% and 30.6%, respectively, of the installed population.

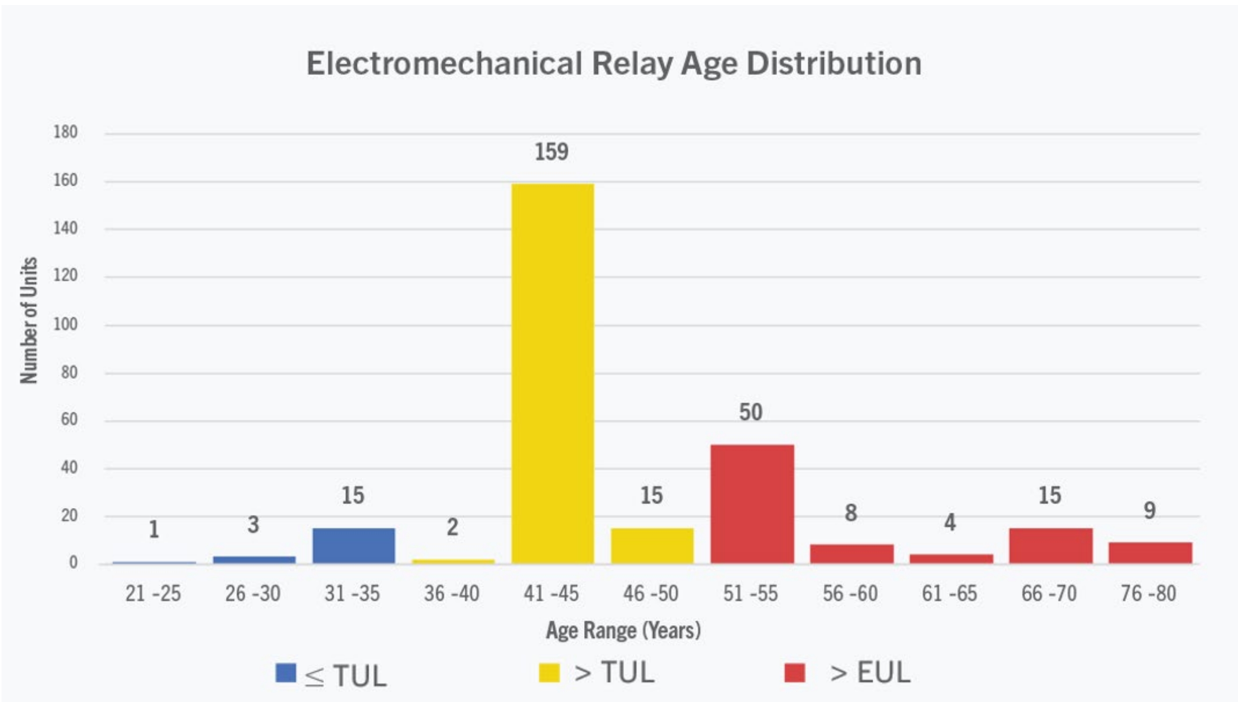


Figure 5.3.2 - 81 Electromechanical Relay Age Distribution

Alectra Utilities has 281 solid state relays installed at its stations. Figure 5.3.2 - 82 illustrates the age distribution of these relays. A total of 132 relays exceed the TUL of 30 years, of which four exceed the EUL of 45 years, representing 47% and 1.4%, respectively, of the installed population.

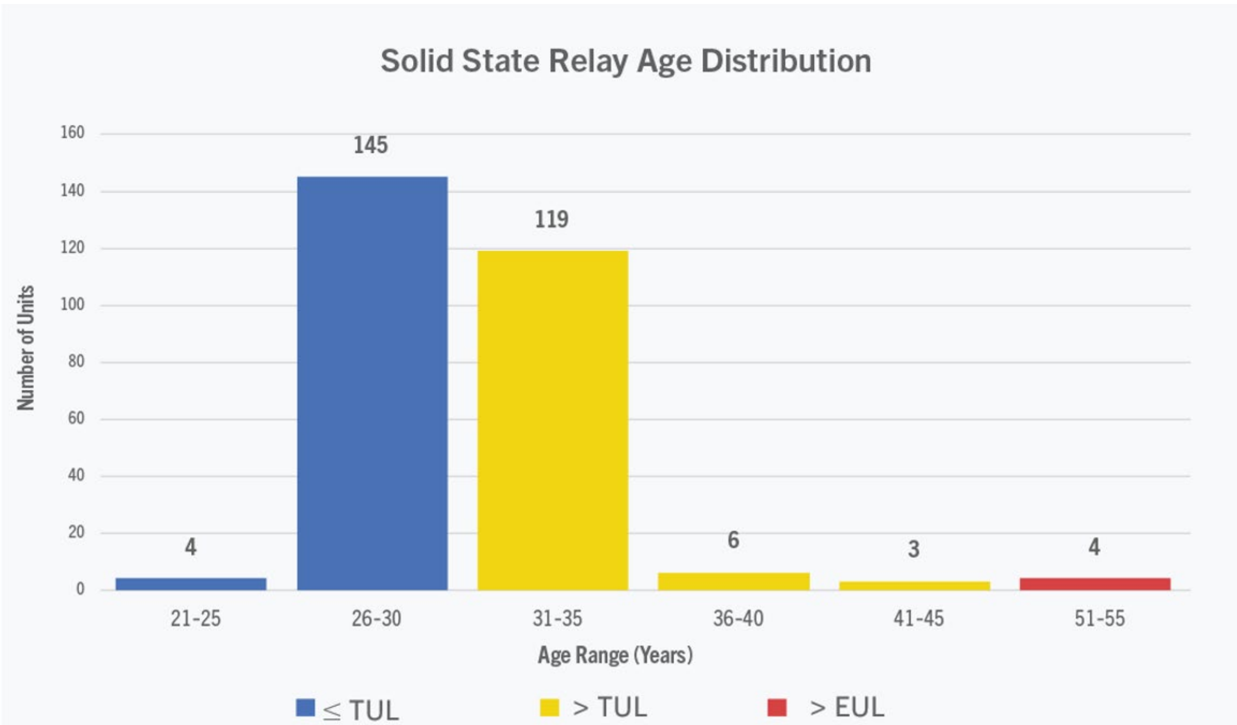


Figure 5.3.2 - 82 Solid State Relay Age Distribution

Alectra Utilities has 1,076 microprocessor-based relays installed at its stations. Figure 5.3.2 - 83 illustrates the age distribution of these relays. A total of 63 relays exceed the TUL of 20 years, representing 5.9% of the installed population. All 63 relays exceed the EUL of 20 years.

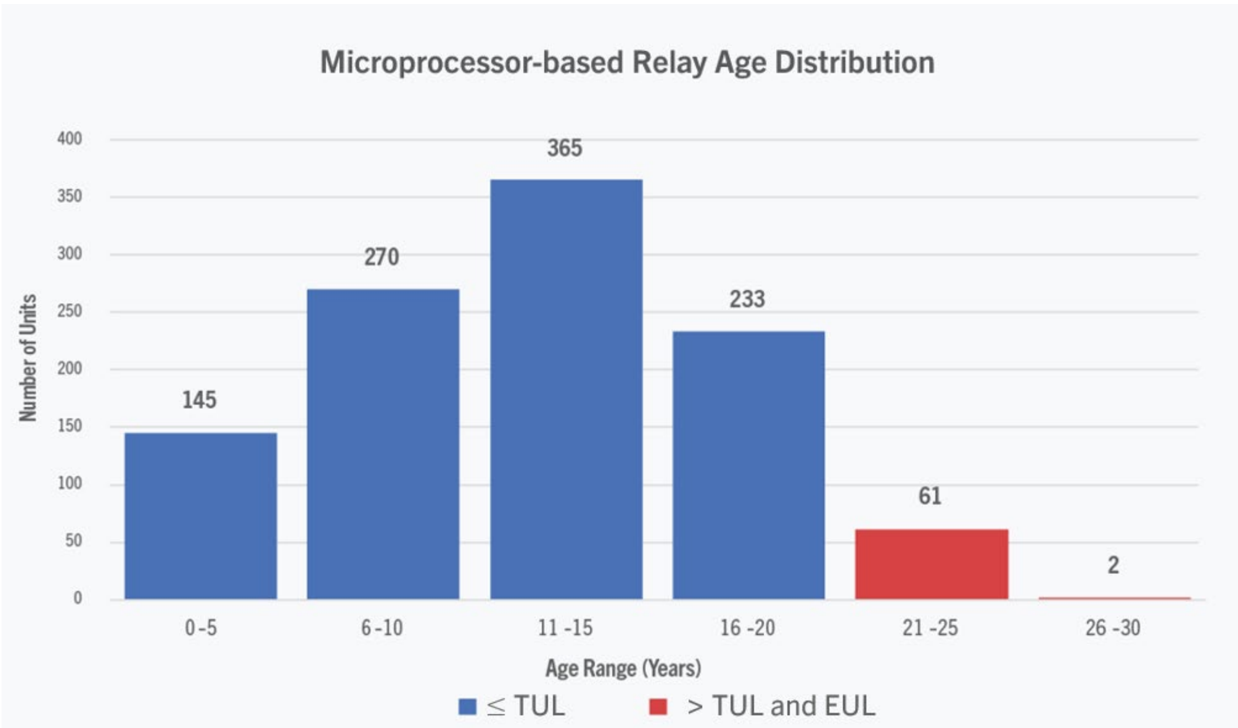


Figure 5.3.2 - 83 Microprocessor-based Relay Age Distribution

Due to the enclosed nature of the asset, a condition assessment is not performed for this asset class. Protection relay replacement that is primarily driven by condition is categorized as a Substation Renewal investment. Relays in deteriorating condition are identified by a history of failure or by increased maintenance or repair requirements. Protection relay replacement that is primarily driven by a need for additional functionality or to support other systems is categorized as a System Service investment.

Station protection and control sustainment practices are detailed in *Chapter 5.3.3 (Section 5.3.3.2 B4)*, replacement practices in *Chapter 5.3.3 (Section 5.3.3 B4)*, investment strategy in *Appendix B04 - Substation Renewal*, and in *Appendix B14 - Enabling Resiliency & Modernization (Section 2.1.4 C)*.

A.3 Metering Assets

As of December 31, 2024, Alectra Utilities has 1,082,934 meters in service to measure electricity usage for its retail and wholesale customers as detailed in Table 5.3.2 - 12. Due to the enclosed nature of the asset, condition assessment is not performed for this asset class. Investment options for metering assets are detailed in *Appendix B06 - Network Metering*.

Table 5.3.2 - 12 Classification and Count of Alectra Utilities' Meters

Type Of Meter	Central	East	West	Southwest	Total Meters
Retail	379,408	390,142	255,157	57,730	1,082,436
Wholesale	182	148	132	36	498
Total	**379,590**	**390,290**	**255,289**	**57,766**	**1,082,934**

A.4 Facilities and Fleet

Table 5.3.2 - 13 lists Alectra Utilities' fleet vehicles by type. Further details on these investments are listed in *Appendix B08 - Fleet Renewal*.

Table 5.3.2 - 13 Fleet Asset Inventory

Vehicle Type	Vehicle Type Count
Heavy-Duty Vehicles	176
Medium-Duty Vehicles	29
Light-Duty Vehicles	332
Trailers	138
Fleet Equipment	48
Overall Total	**723**

Alectra Utilities owns approximately one million square feet of space across seven cities. Alectra Utilities has three administrative offices, located in Hamilton, Mississauga, and Vaughan. In addition, Alectra Utilities has six Operating Centres, which are situated in Hamilton, Markham, Guelph, Barrie, Brampton, and St. Catharines. All facilities consist of fully serviced buildings equipped with HVAC systems, plumbing, and electrical services. Each facility is supported by an emergency backup generator. Three of the facilities include control rooms, and five locations accommodate call centre support staff. The condition assessment for facilities is detailed in

Appendix N - Baseline Property Condition Assessment. Investment options for facilities are detailed in *Appendix B07 - Facilities Management*.

B Asset Capacity & Utilization

The core guiding principles that Alectra Utilities follow for system planning, feeder and station capacity thresholds are listed below.

- Alectra Utilities applies a deterministic N-1 network planning approach. Under this approach, Alectra Utilities will be able to continue supplying connected loads when a single major network station element is out of service until it is repaired or replaced (hence, “N-minus-1”). This planning approach requires sufficient capacity redundancy within the distribution network to withstand a single network station element outage without interrupting service to customers.
- Alectra Utilities constructs and operates an “open looped” network design, which requires multiple feeders to be interconnected via normally-open points. The utility can close these points to create a circuit and re-route the flow of electricity to customers to maintain service when an element of the network (e.g. a station transformer) fails or is otherwise taken out of service. Where technically and economically feasible, Alectra Utilities will connect loads of 500 kVA or greater with a looped supply connection.
- Alectra Utilities continues to interconnect legacy utility systems where feasible (i.e. create tie points between legacy utility distribution systems) to increase system utilization, improve reliability, improve resiliency, and provide back-up capability.
- Alectra Utilities operates primary feeders (44/27.6/13.8/8.32/4.16kV) under normal conditions (summer peak) to a maximum loading that is the lesser of 2/3rd egress cable rating or 2/3rd of the 600 amp contingency rating.
- Alectra Utilities operates primary feeders under contingency conditions to a maximum loading rating of the lesser of the egress cable or 600 amp.
- Alectra Utilities plans to implement triad configuration for substations when applicable. This includes either three substations interconnected through their secondary feeders, or two transformers at a single substation site where interconnection to adjacent substations is not feasible.

- Where a transmission system connected transformer station is required, Alectra Utilities plans to continue building Dual Element Spot Network (DESN) transformer stations.
- Alectra Utilities utilizes a 10-Day Limited Time Rating (10-Day LTR) for transformer station capacity planning criteria.
- A transformer that exceeds its Oil Natural Air Natural (ONAN) rating (an indication that the transformer is over the base rating) will trigger a review of substation loading, including analysis of load transfers to adjacent substations, the loading impact of future growth, land availability, resource availability, and other contingencies. Capacity augmentation will only be considered when a transformer will exceed its respective maximum top-stage rating; ONAN for transformers with no fans, ONAF for transformers with single-stage fans, or ONAF/ONAF for transformers with dual stage fans.
- Alectra Utilities will maintain spare transformers to mitigate the risk of a prolonged station transformer loss.

The subsequent sections describe the guidelines for determining the transformer loading for the TSs and MSs.

B.1 Station Utilization

B.1.1 Transformer Stations Utilization

The transformer Limited Time Rating (LTR)[9] is used as the transformer loading guideline.

The LTR rating is used as the transformer station loading guideline for the following reasons:

- If one transformer fails in a typical DESN station, the remaining transformer will carry the load of the entire station. The transformer will lose 2% additional life if it is loaded at its LTR rating for ten days.
- Replacing the failed transformer with a system spare transformer takes approximately ten days

[9] The transformer load capability calculated on the basis of 140°C (for 65°C rise) maximum hot spot temperature (ANSI Standard) and a 2% aging limit (HONI practice) is called "10 day Limited Time Rating" (LTR). For a transformer with a 50-year life, the allowable loss of life, under contingency loading, is 2% per year or 0.2% per day for 10 days.

- For a transformer outage longer than ten days, the transformer loading must be brought to its base rating. This can be accomplished by load transfers above name rating to adjacent stations or by load shedding.

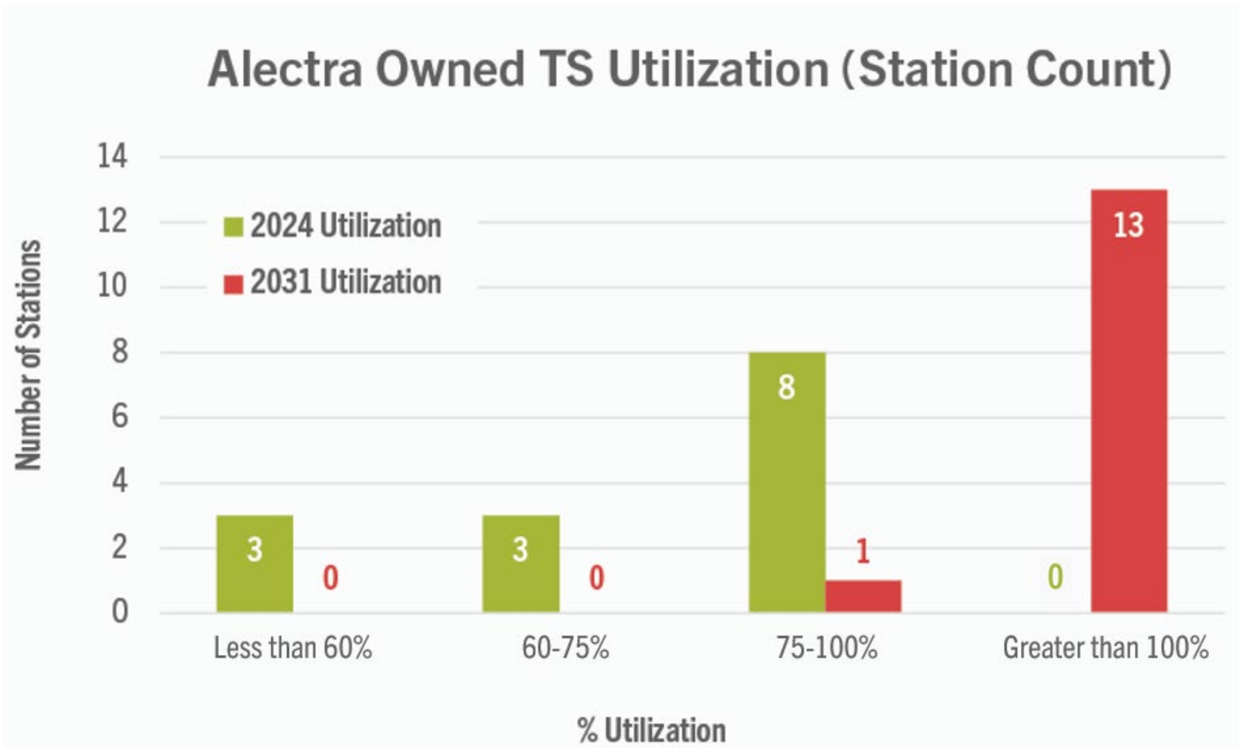


Figure 5.3.2 - 84 Alectra Utilities' Owned TS Utilization

Figure 5.3.2 - 84 illustrates TS utilization in 2024, with growth projections to 2031 for the TSs supplying the Alectra Utilities service area, assuming no augmentation. The utilization is based on the current loading and 2031 numbers are based on Alectra Utilities load forecast process (refer to *Appendix J - Load Forecast & System Capacity Adequacy Assessment Report*). Thirteen Alectra Utilities owned stations are projected to be over the LTR by 2031.

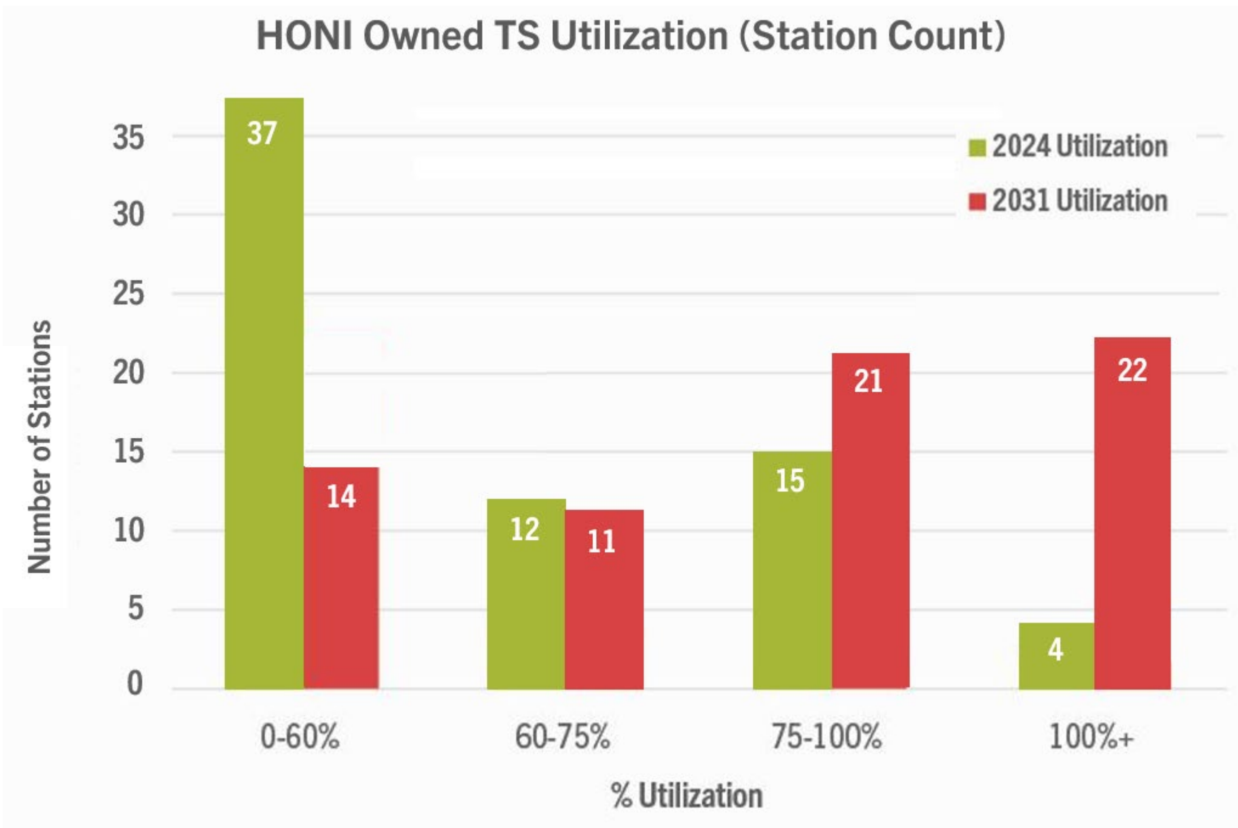


Figure 5.3.2 - 85 HONI Owned TS Utilization

Figure 5.3.2 - 85 illustrates TS utilization in 2024, with growth projections to 2031 for HONI owned TSs. HONI owns 22 stations that are projected to exceed the LTR rating. Alectra Utilities continues to monitor the load, and there are opportunities available for load transfer to other stations. Alectra Utilities continues to work with HONI and IESO to determine the long-term needs in the area.

In summary, the Transformer assets are at or near optimal limits and are being prudently utilized (refer to *Appendix B13 - Stations Capacity* for details on proposed approach and plans to add more TS capacity for future growth and continue to manage the assets prudently).

B.1.2 Municipal Stations Loading

MSs are supplied from 44kV, 27.6kV or 13.8kV circuits, and step down the voltage to one of the four distribution levels: 27.6kV, 13.8kV, 8.32kV, and 4.16kV. Each substation typically has two to four feeders, supplying a combination of three-phase and single-phase loads. Substation load back-up is required under contingency conditions (e.g. station equipment failure) and non-contingency purposes (e.g. planned outage for maintenance or capital work). Under these conditions, the substation load is transferred to adjacent substations using feeder ties.

A deterministic approach requires that supply be maintained during any N-1 contingency condition. This requirement extends to substation planning to ensure that load associated with the loss of the largest transformer element in the substation network can be maintained by adjacent substations while remaining within the substations' transformer contingency rating. The contingency rating is determined by the cooling capabilities of the transformer and is equivalent to the highest cooling rating: ONAN (100% of base rating) for self-cooled transformer units, ONAF (133% base rating) for transformer units with single-stage fans, and ONAF/ONAF (166% of base rating) for transformer units with dual-stage fans.

Two network configurations govern N-1 contingency support requirements:

B.1.2.1 Two Substation Network

In a two-substation network configuration with similar transformer rating, each substation transformer in the network must operate below 50% of its contingency rating to satisfy the N-1 criteria. If 50% is exceeded, the adjacent substation does not have enough capacity to accommodate the entire load of the substation that experienced an outage. Any load transferred from the out-of-service substation that is beyond the 50% threshold is considered 'Load at Risk,' as it exceeds the contingency rating. This is illustrated in Figure 5.3.2 - 86.

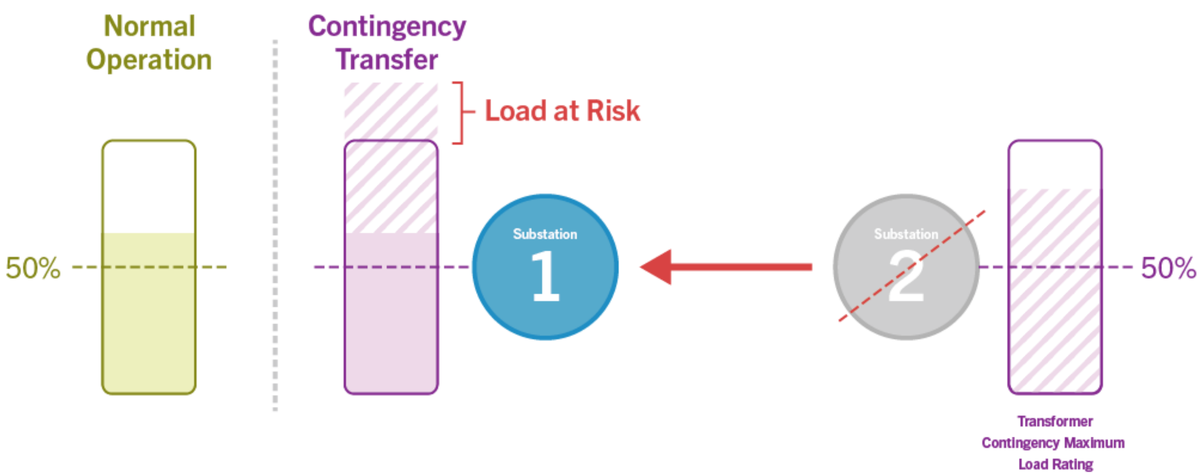


Figure 5.3.2 - 86 Contingency N-1 Criterion for Two Substation Network

B.1.2.2 Three Substation Network

In a network comprised of three or more substations, the N-1 contingency criterion is satisfied even if substation transformers in the network are loaded beyond 50% of the contingency rating. At a minimum, three substations are required to fully satisfy the N-1 contingency criterion when exceeding 50% of the transformer contingency rating, thereby establishing the 'Triad' configuration, as illustrated in Figure 5.3.2 - 87.

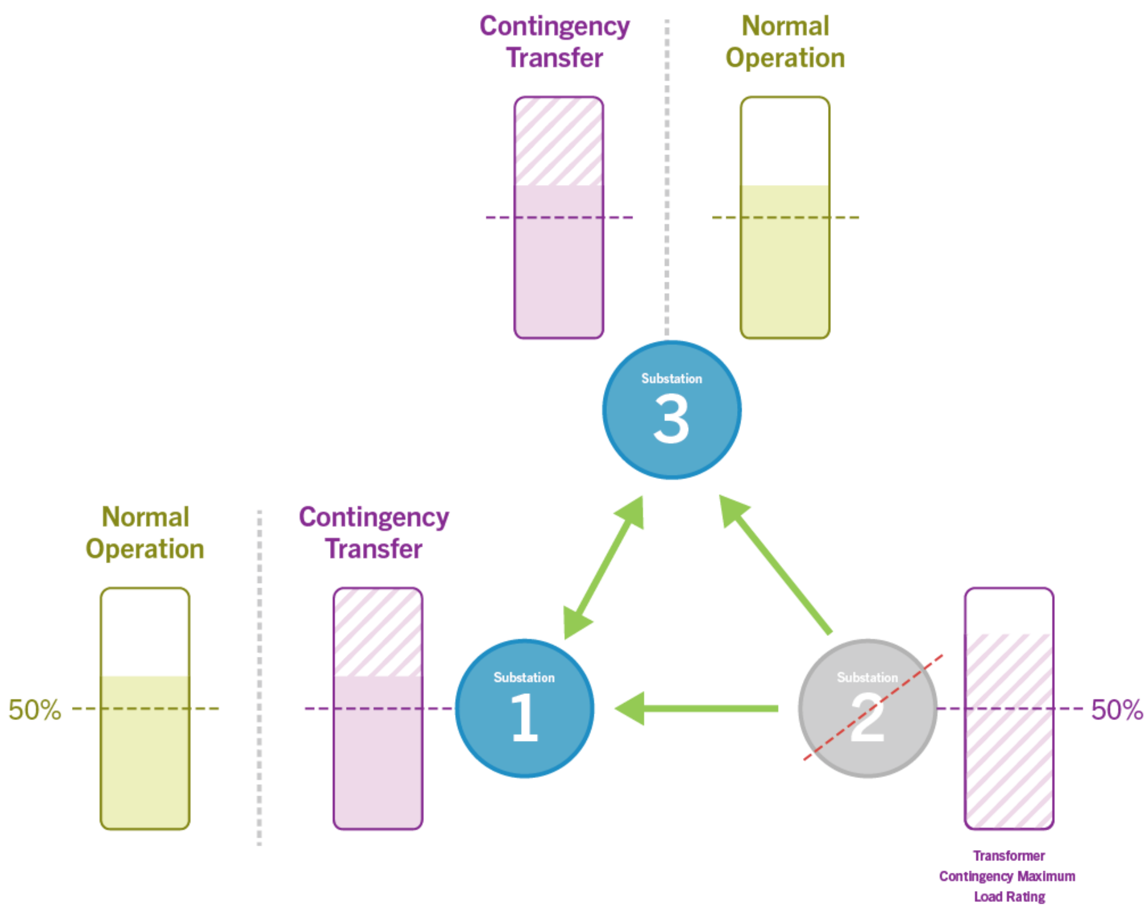


Figure 5.3.2 - 87 Contingency N-1 Criterion for Three Substation Network

The Triad configuration ensures that upon loss of a single substation transformer, the two remaining transformers can accommodate the transferred load in addition to their own native load, thereby mitigating any potential load shedding as a result of the outage. The Triad configuration lends itself to either a network of electrically isolated substations, or to an interconnected network of substations constrained by feeder connections with transfers limited by thermal limits or nominal voltage thresholds.

Figure 5.3.2 - 88 illustrates the MS loading in 2024 and 2031 relative to the maximum rating. The MS utilization is based on current loading and Alectra Utilities load forecast process (refer to *Appendix J - Load Forecast and System Capacity Adequacy Assessment Report* for further details).

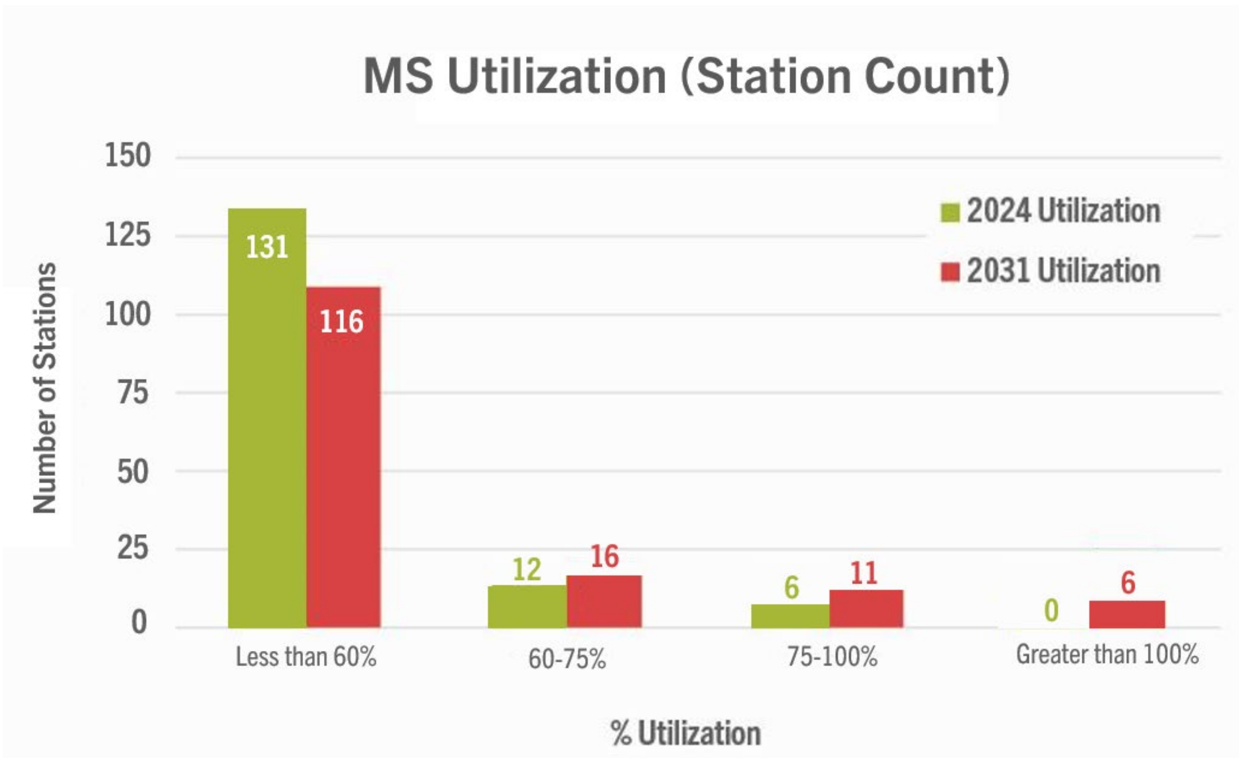


Figure 5.3.2 - 88 Alectra Utilities Municipal Station Utilization

In a two station network each station should be operating at 50% of the rating while in the triad configuration the n-1 criteria can still be satisfied with up to 66% of the rating to accommodate contingency transfers. Figure 5.3.2 - 88 illustrates that the 131 Municipal Stations are at acceptable loading conditions which will decrease to 116 by 2031. In addition, there are six locations that are above optimal loading conditions, which will increase to 17 by 2031. Alectra Utilities will be required to augment the capacity at these stations (refer to *Appendix B13 - Stations Capacity* on Alectra Utilities' plan to add new capacity to provide for future growth and continue to prudently manage the assets).

Typical TS construction takes 5-7 years, where MS's construction/in-service takes 3-5 years. Alectra Utilities' goal is to identify TS and MS needs in time to ensure that sufficient lead time is available for permit approvals, design, procurement, construction and the commissioning of facilities before peak demand load exceeds available capacity.

B.2 Feeder Loading

Alectra Utilities operates 1,371 feeders across its service territory. Table 5.3.2 - 14 shows the inventory of feeders as of 2024.

Table 5.3.2 - 14 Asset Inventory (Distribution Assets)

Number of Feeders				
4.16kV	8.32kV	13.8kV	27.6kV	44kV
268	19	692	300	92

Alectra Utilities' planning criteria specifies that the 44/27.6/13.8/8.32/4.16kV feeder loading under normal conditions during summer peak will be the lesser of two-thirds egress cable rating or two-thirds of the 600 amp contingency rating. During contingency conditions, the 44/27.6/13.8/8.32/4.16kV feeder loading will be the lesser of the egress cable rating or 600 amp.

Alectra Utilities' system configuration consists of open looped network design with multiple feeders interconnected via normal open points. The two-thirds loading on the feeder ensures that in a contingency condition, either planned or unplanned, the feeder can safely carry the load of the other feeder. Operating feeders over the planning limit may present considerable risk, however in some cases depending on system configuration as well as projects planned in the near term, some feeders are allowed to operate over the planning limit.

Alectra Utilities conducts annual load forecasting and load balancing to ensure that all feeders stay within their normal loading limits. Feeder augmentation projects are proposed to relieve congestion on feeders. Additional feeder expansions are carried out under customer growth projects to meet customer demand from new connections. Projects are implemented using a phased approach based on load growth, funding availability and customer development progress, which allows the utility to pace investments just-in-time for connecting new developments while mitigating rates impact and maintaining service reliability for existing customers in the area.

Figure 5.3.2 - 89 to Figure 5.3.2 - 93 illustrate the asset utilization of feeders and the associated voltage class relative to the planning limits. These numbers are based on the current loading and projected loading based on Alectra Utilities load forecast process (refer to *Section 5.3.2.2 B* and *Appendix J - Load Forecast & System Capacity Adequacy Assessment Report*).

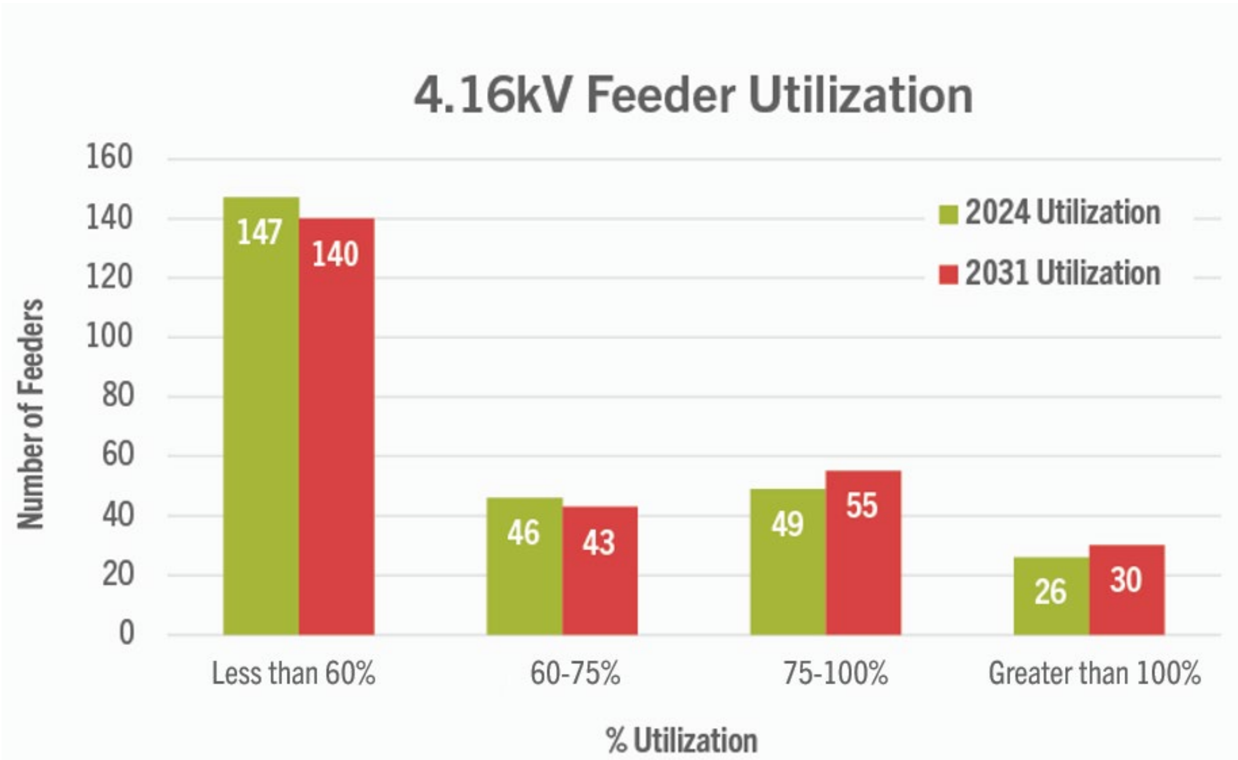


Figure 5.3.2 - 89 4.16kV Feeder Utilization

Figure 5.3.2 - 89 illustrates the utilization of 4.16kV feeders. The 4.16kV is the lowest distribution voltage class in Alectra Utilities' service territory. The majority of these feeders are within the planning limit, and therefore during contingencies, loads can be transferred between the feeders. However, 26 of the 4.16kV feeders are over the planning limit. By 2031, 30 feeders will be over the planning limit due to projected load growth.

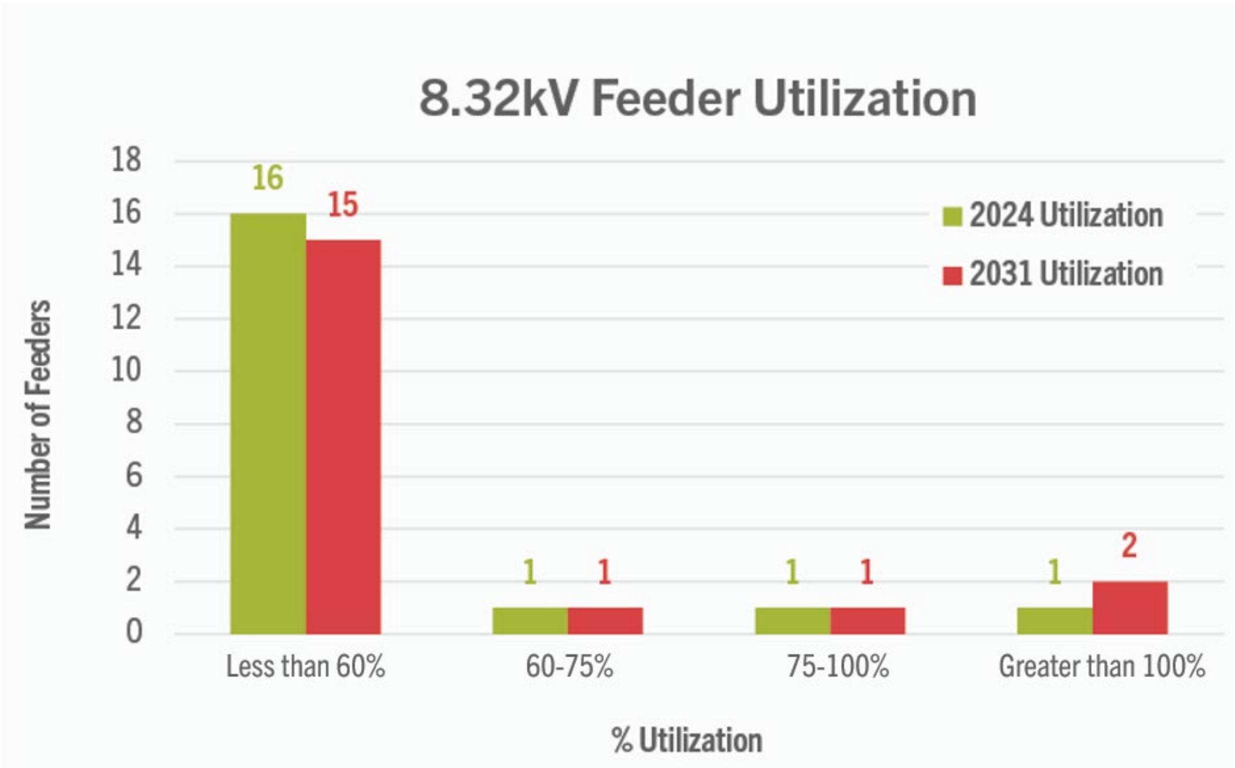


Figure 5.3.2 - 90 8.32kV Feeder Utilization

Figure 5.3.2 - 90 illustrates the utilization of the 8.32kV feeders. One of the 8.32kV feeders is over the planning limit. By 2031, two feeders will be over the planning limit due to projected load growth.

Alectra Utilities plans to convert 4.16kV and 8.32kV to 13.8kV or 27.6kV and as such no augmentation efforts are proposed in this DSP (refer to *Appendix B01 - Overhead Asset Renewal)*.

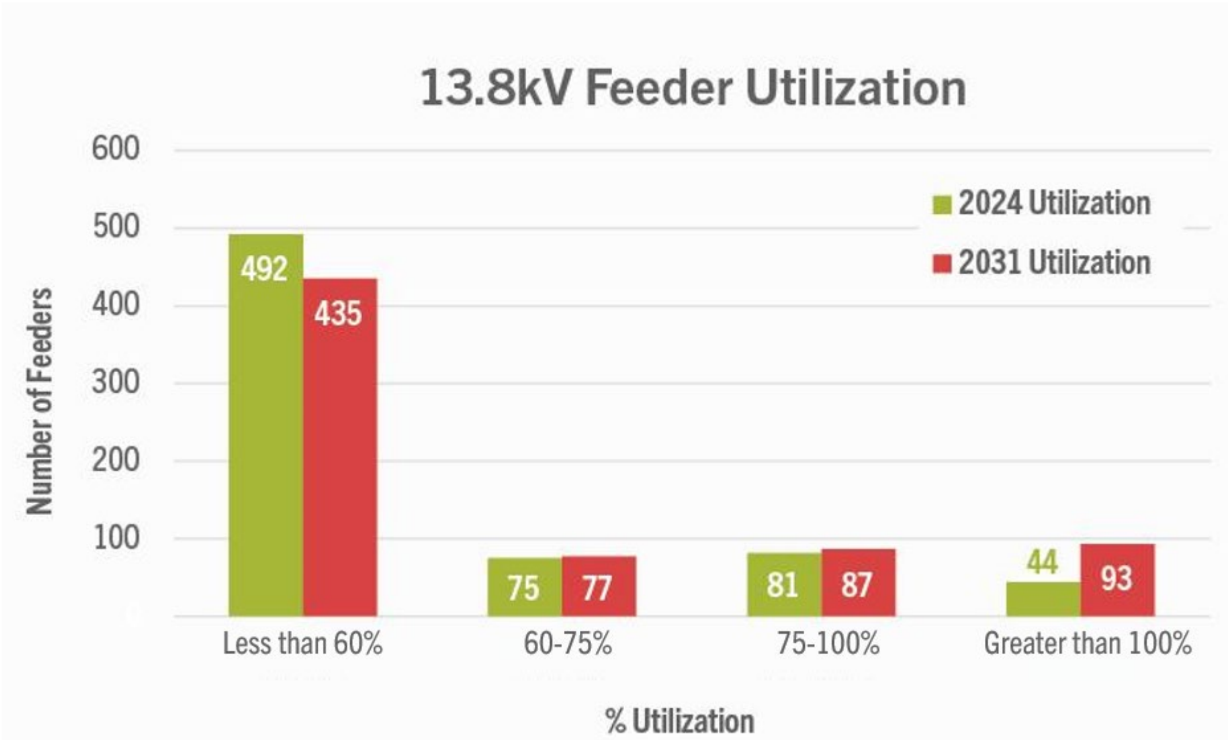


Figure 5.3.2 - 91 13.8kV Feeder Utilization

Figure 5.3.2 - 91 illustrates the utilization of the 13.8kV feeders. Currently, 44 feeders are over the planning limit, and due to projected load growth and without intervention, this is forecast to grow to 93 feeders by 2031. Alectra Utilities will manage the feeder loading by load balancing through distribution changes, such as adding tie points and sectionalizing switches. Alectra Utilities also plans to build additional feeders to augment existing feeders. The details can be found in *Appendix B12 - Lines Capacity*.

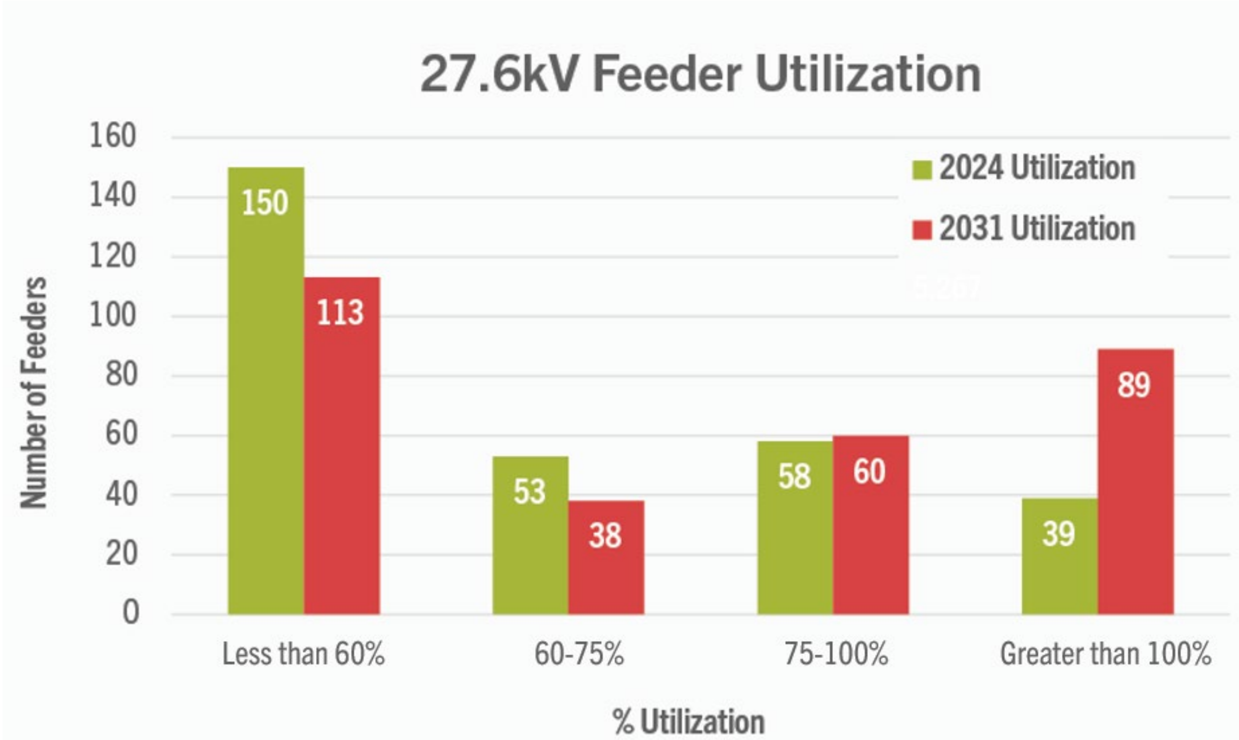


Figure 5.3.2 - 92 27.6kV Feeder Utilization

Figure 5.3.2 - 92 illustrates the utilization of the 27.6kV feeders. 39 feeders are currently over the planning limit, and due to projected load growth and with no intervention, 89 feeders will be over the planning limit by 2031. Alectra Utilities will manage feeder loading by load balancing through distribution changes, such as adding tie points and sectionalizing switches. Alectra Utilities also plans to build additional feeders to augment existing feeders. The details can be found in *Appendix B12 - Lines Capacity*.

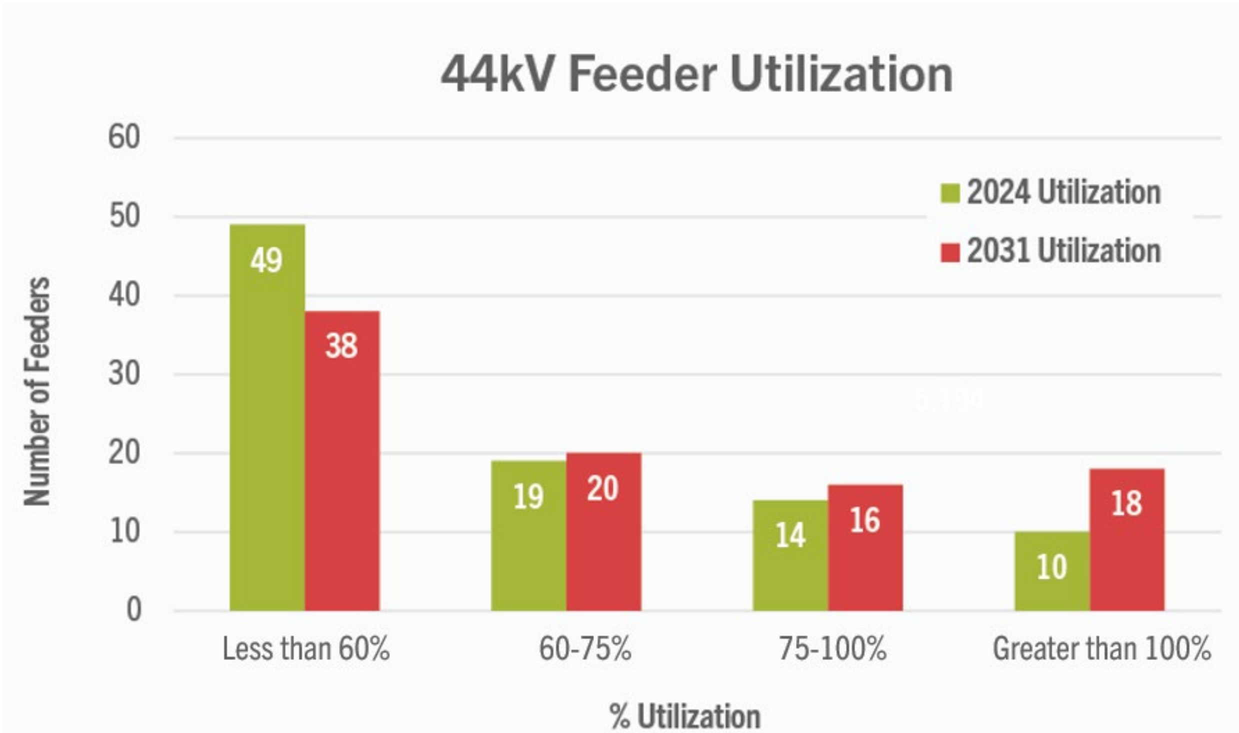


Figure 5.3.2 - 93 44kV Feeder Utilization

Figure 5.3.2 - 93 illustrates the utilization of the 44kV feeders. Ten feeders are currently over the planning limit, and due to projected load growth and with no intervention, 18 feeders will be over the planning limit by 2031. Alectra Utilities will manage the feeder loading by load balancing through distribution changes, such as adding tie points and sectionalizing switches. Alectra Utilities also plans to build additional feeders to augment the existing feeders. The details can be found in *Appendix B12 - Lines Capacity*.

5.3.3 Asset Lifecycle Optimization Policies and Practices

Alectra Utilities manages its station, distribution system and revenue metering assets throughout their lifecycle to optimize asset performance and useful life, while delivering maximum value to customers with due regard to system reliability, safety, regulatory requirements, cost, customer service requirements, and environmental considerations. This section describes Alectra Utilities' asset sustainment practices and lifecycle optimization methodologies that support the Asset Management Process in identifying investment needs, sustaining in-service assets, and planning system renewals.

- **Section 5.3.3.1** provides an overview of the asset sustainment practices, including the maintenance, replacement, and refurbishment strategies of station, distribution and metering assets.
- **Section 5.3.3.2** details the maintenance practices that support optimal lifecycle management and aim to extend the useful life of an asset where possible.
- **Section 5.3.3.3** describes planned asset replacement practices, key decision drivers, and how capital investment planning is customized for each specific asset class.
- **Section 5.3.3.4** describes refurbishment practices for comprehensive assessment and asset rebuilding opportunities to extend the useful life of major assets.
- **Section 5.3.3.5** explains how system renewal and expansion investments impact the overall maintenance requirements of Alectra Utilities' assets.
- **Section 5.3.3.6** explains Alectra Utilities' asset lifecycle management approach and use of Copperleaf's Predictive Analytics (PA) in optimizing the quantity and pacing of distribution asset classes like poles, transformers, switches, and switchgear.

Lifecycle optimization practices for general plant assets (e.g. fleet and information technology) are discussed in a separate section of this DSP, in *Chapter 5.4.2 2027-2031 Investment Overview*.

5.3.3.1 Overview of Alectra Utilities' Lifecycle Optimization Practices

In managing the station and distribution system, Alectra Utilities' main objective is to optimize asset performance with due regard for system reliability, safety, cost, customer service requirements, and environmental considerations, while maximizing long-term value through risk-informed decision-making, regulatory compliance, and sustainable asset lifecycle management. This is referred to as Alectra Utilities' Asset Sustainment Practices. More specifically, the company's Asset Sustainment Practices aim to optimize total cost of asset ownership in a sustainable manner through maintenance, replacement, and refurbishment activities. *Section 5.3.3.2*, *Section 5.3.3.3* and *Section 5.3.3.4* describe the evaluation of whether assets should remain in service or undergo maintenance, replacement, or refurbishment. In making these determinations, Alectra Utilities considers a multitude of factors including asset condition, failure risk, functionality, safety, environmental impacts, loading, and compliance with current standards.

Figure 5.3.3 - 1 provides an overview of Alectra Utilities' Asset Sustainment practices.

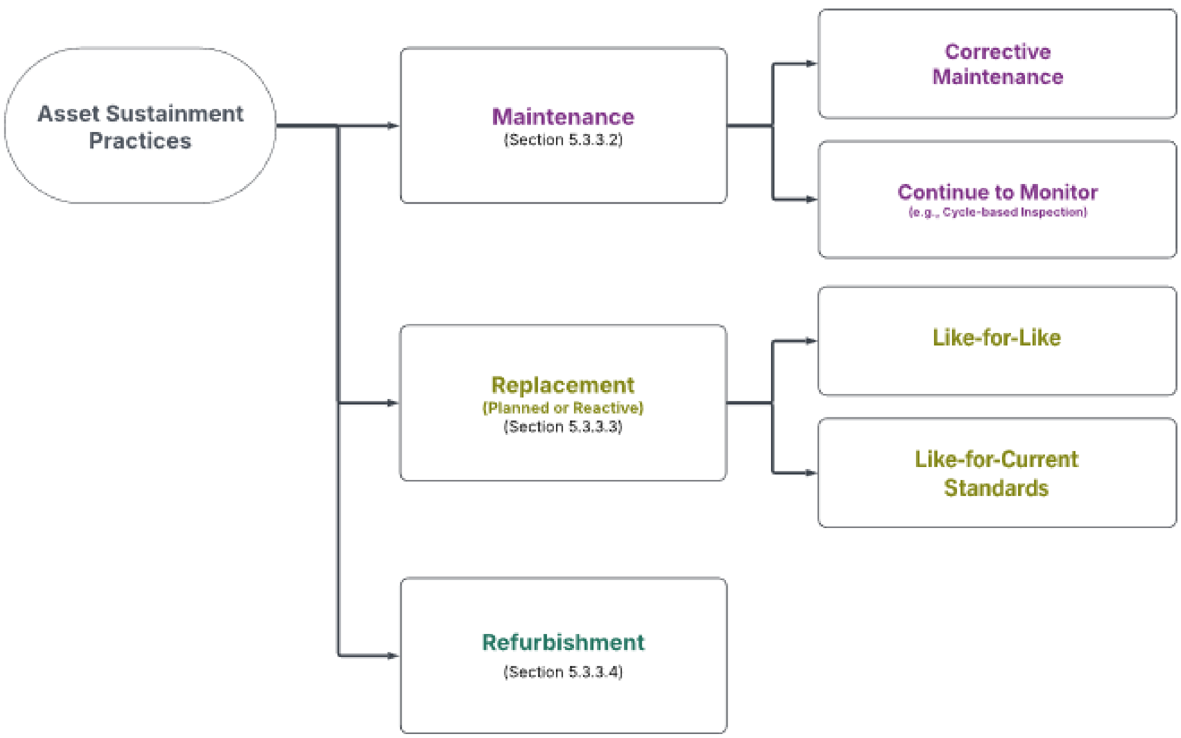


Figure 5.3.3 - 1 Sustainment Practices

The integrated practices that underpin Alectra Utilities' asset sustainment practices involve fixed or variable cycles of inspection, testing, maintenance activities, and other defect or failure capturing processes (as discussed in *Section 5.3.3.2*). These practices result in asset renewals, refurbishment of major assets, where applicable, corrective maintenance for in-service repairs, or continued monitoring to assess asset condition. Capital investment planning from business case development and optimization are detailed in *Chapter 5.3.1 Asset Management Process Overview* and *Chapter 5.4.1 Capital Expenditure Summary*. Through its effective inspection, testing, and maintenance programs, Alectra Utilities captures information on signs of asset deterioration and defective components to properly assess and prioritize mentioned interventions while balancing operational maintenance costs and risks. At a high level, these programs include the following, with details on type of activity and cycles mentioned in Table 5.3.3 - 2:

- Overhead distribution system inspections for transformers, poles, insulators, switches, arrestors, and hardware attachments (e.g. guy wires, cross arms, and ground wires)
- Underground distribution system inspections for transformers, bushings, elbows, civil chambers, and pad-mounted switchgear. It also includes detailed inspections of high voltage electrical rooms (i.e. vaults) containing components such as transformers, switches, cabling, doors, ceilings, drains, and internal lights.
- Station asset inspections including the wholesale meter installations, with testing and maintenance activities

Results from inspection, testing, and maintenance programs are used as inputs to Alectra Utilities' Asset Condition Assessment (ACA) process[1]. ACA establishes Health Index (HI) values for eleven major asset groups. These HI values provide an indication of asset condition across the HI spectrum from "Very Poor" to "Very Good". Health Index classifications are as described in Figure 5.3.2 - 19 in *Chapter 5.3.2 (Section 5.3.2.2 A)*.

[1] Refer to *Appendix E Asset Condition Assessment - 2023*

Asset groups with HI scores covered in the ACA are shown in Table 5.3.3 - 1.

Table 5.3.3 - 1 Asset Groups Covered in ACA Process

Distribution Underground & Vaults	Distribution Overhead	Station
• Pad-mounted Transformers • Vault Type Transformers • Underground Cables • Pad-mounted Switchgear	• Pole-mounted Transformers • Load Interrupting Switches • Wood Poles • Concrete Poles • Overhead Conductors	• Power Transformers • Circuit Breakers • Station Switchgear

The overhead and underground distribution assets and station assets are inspected and evaluated against pre-set criteria and the results are recorded electronically using computer tablets. Inspection records for distribution assets are tied to unique asset records in Alectra Utilities' GIS system, which provides a centralized location for validated inspection records that can be extracted for ACA purposes. This ensures that Alectra Utilities uses the most accurate asset data when planning its asset lifecycle optimization approach. Station inspection results, as well as maintenance and repair activities and test results, are stored in Cascade, a Computerized Maintenance Management System (CMMS). Annual condition surveys are also conducted for station assets.

Alectra Utilities leverages the ACA results to generate detailed HI maps overlaid with the failure data for each distribution asset. These specialized maps enable integration of lagging asset performance indicators in a given neighborhood and aid in the identification of geographic clusters of deteriorated assets (e.g. "Poor" or "Very Poor" condition from ACA). Using an overlay mapping methodology, Alectra Utilities can view multiple asset types with their corresponding HI values to support engineering analysis. This approach enables subject matter experts (SMEs) to focus on and assess locations where rebuild options can be designed and executed more efficiently than via individual spot replacements. Figure 5.3.3 - 2 provides an excerpt from an overlay map. This map excerpt highlights underground cable segments in "Very Poor" condition (red line), documented cable failures, and "Very Poor" condition distribution transformers and switchgear (red triangles and red squares, respectively) identified through the ACA process. The analysis enabled by the overlay map supported the decision to proceed with a coordinated rebuild project in this area, where multiple deteriorated assets require replacement. The proposed rebuild offers greater logistical efficiency and minimizes customer disruption compared to executing discrete projects for each asset type.

[redacted]

Through planned asset replacement strategies, Alectra Utilities aims to mitigate failure risks that have significant impact to public or employee safety, financial cost, system reliability, customer service interruption, environmental impact, and regulatory consequences. The decision to replace an asset is typically driven by asset deterioration and failure risk, failure rate, functional obsolescence, historical performance, alignment with applicable standards, and planning and execution efficiencies, and refurbishment is not feasible. In areas with a high concentration of assets in deteriorated condition and past or nearing end-of-life, Alectra Utilities prioritizes planned rebuild projects rather than spot replacements. In this regard, Alectra Utilities uses condition data, asset age, and failure rates for an asset class to establish long-term failure projections.

Alectra Utilities uses asset condition, age, and failure data to develop long-term asset replacement projections using Copperleaf Asset, for major distribution asset classes of poles, transformers, switchgear, and switches. Copperleaf Asset applies predictive analytics to model asset population behaviour (via Predictive Analytics tool) and determines the timing and quantities of replacements that deliver the greatest value across reliability, safety, environmental, and financial measures. Input data includes asset demographics, loading information, replacement costs, and equipment failure information. Based on this information, Copperleaf's Predictive Analytics (PA) tool generates renewal plans on the aggregate of optimal replacement timing of individual assets. These renewal quantities are further modified according to Alectra Utilities' pacing strategies; Accelerated, Moderate, and Reduced. The results are used to inform business cases in Copperleaf Portfolio and to support both current and future DSP planning periods for mentioned asset classes. This process allows Alectra Utilities to maintain a long-term view of asset demographics to reduce variability in investment needs, avoid sudden rate impact and limit rate volatility for customers, and improve the alignment of resources with system renewal requirements.

Figure 5.3.3 - 3 illustrates that, based on Alectra Utilities' ability to execute and in consideration of customer rate impacts, the DSP plan for asset renewal investments cannot address all system renewal needs over the 2027-2031 period. The system renewal needs analysis which involves major distribution asset classes, such as poles, underground cable, switchgear, transformers, and overhead switches, but does not include station and metering asset classes, involves examining remaining backlog year after year. This examination considers the current backlog, the forecasted quantity of deteriorated assets, the planned replacements, and the estimated yearly outage events based on historical reliability data and ACA results. The DSP plan nears addressing the level of system needs by 2031, but with a shortfall. Despite the use of condition and risk-based prioritization, the current plan for system investments does not fully address projected renewal needs, largely due to practical aspects of the logistical ramp-up required in terms of resources.

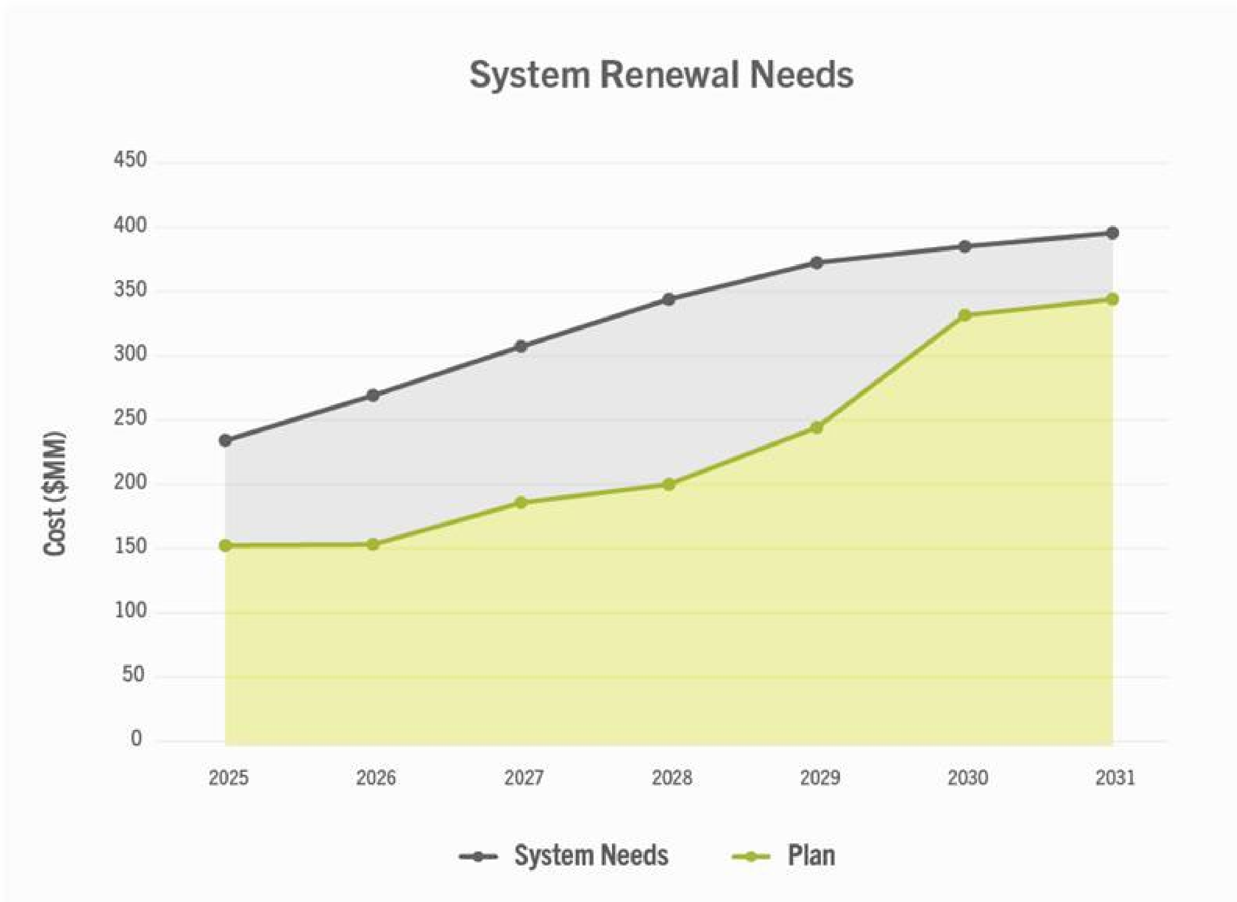


Figure 5.3.3 - 3 System Renewal Needs (Excludes Station and Metering)

Pacing and prioritization of asset replacements follow different approaches depending on the asset type. Pacing is time based, while prioritization is based on relevant drivers such as severity of asset deterioration, obsolescence, and level of reliability, safety, and environmental risks. The determination of both pacing and prioritization are key parts of the lifecycle optimization policies and practices.

Planned asset replacements are organized into projects and programs which are paced to optimize resource allocation, minimize customer outages, minimize the need for reactive capital work, avoid sudden increases in renewal investment, and accommodate major procurement efforts. Compared with reactive work, planned renewal projects make more efficient use of resources and scheduled outages, providing a more economical and less disruptive approach. Alectra Utilities identifies longer-term planned asset replacement needs (i.e. two years or more) through the ACA process. Shorter term asset replacement needs are identified through ongoing inspecting, testing, and maintenance activities which flag assets in deteriorated condition requiring replacement or refurbishment within the next year to sustain performance, protect public safety, and reduce environmental risk. Alectra Utilities undertakes repair or maintenance activities where they are feasible, sustainable, and economical.

While the ACA is a primary input to Alectra Utilities' asset management process, a broader set of internal and external drivers also informs asset sustainment plans[2] as part of the Identification of Investment Needs as discussed in *Chapter 5.3.1 Asset Management Process Overview*. SME evaluate distribution and station asset ACA results, and other internal and external drivers, to determine system renewal needs and to frame technical solutions and develop investment business cases. Business cases are documented in the Copperleaf Portfolio, which facilitates the optimal allocation and pacing of the utility's investments across all categories. The optimization process accounts for the risks and benefits of investments in conjunction with their present value. As a proven portfolio optimization solution, Copperleaf Portfolio anchors a uniform approach to Alectra Utilities' analysis and verification of many capital projects with a significant annual spend across all operating zones. More specifically, it allows a myriad of scenarios spanning multiple years to be modelled to inform the development of an optimal capital portfolio that balances financial and resource constraints, as well as investment benefits and risks. The Copperleaf Portfolio application also provides a single repository for all capital investment information which can be updated to reflect new information.

5.3.3.2 Asset Maintenance Practices

Sustaining the condition of an asset through structured maintenance programs is a central tenet of prudent asset lifecycle management. Maintenance practices allow for regular condition monitoring and timely servicing and repairs to extend the life of a given asset. Alectra Utilities performs the following activities related to distribution and station assets to maximize asset value in alignment with optimal lifecycle management:

[2] "Sustainment" is considered a form of renewal where options exist other than replacement (e.g. targeted repairs on distribution switchgear) other than outright replacement of an asset.

- **Inspection and Testing**: Assessing the current operating condition and functionality of an asset to inform appropriate interventions
- **Maintenance**: Sustaining the condition of the asset through regular preventative and ACA-informed maintenance activities (e.g. dry ice cleaning)
- **Corrective Maintenance**: Performing minor repairs to enhance the current condition and extend the life of an asset

To enhance access to asset condition data and streamline inspection record collection and validation, Alectra Utilities completed a GIS convergence project in 2021. This initiative consolidated four legacy Utilities' asset datasets and related workflows into a single standardized GIS platform. Legacy Guelph Hydro's GIS system remains separated as of 2025 and is expected to converge with the Alectra Utilities' harmonized GIS system within the 2027-2031 period. The GIS system supports MobileViewer Advantage (MVA), a mobile asset inspection tool. MVA is directly integrated with the GIS system, thereby providing mobile access to centralized and validated distribution asset inspection records.

Inspection and testing activities are vital for continuously identifying the condition of assets in the field. Alectra Utilities collects standardized inspection attributes for each major distribution asset class according to manufacturer recommendations or condition factors used to establish a Health Index in the ACA. Inspection frequency is determined based on regulatory requirements and utility best practice. Intervals may be shortened for an asset where age or condition signals elevated risk to identify defects prior to premature failure of a critical asset, which is key to optimal lifecycle management.

In addition to inspection and testing programs, Alectra Utilities employs other internal and external processes to capture deficiencies. Figure 5.3.3 - 4 describes the input processes involved in deficiency capturing and the associated asset sustainment interventions.

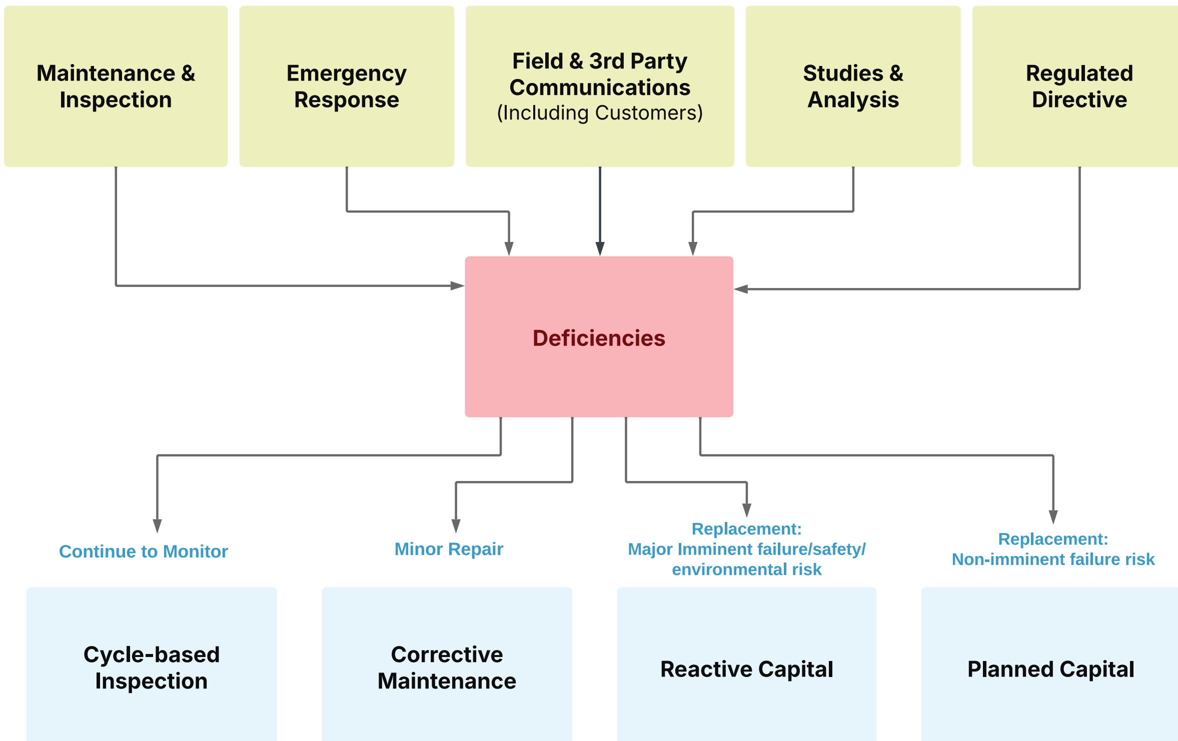


Figure 5.3.3 - 4 Deficiency Capturing Process

Maintenance activities sustain the current condition of the asset and are performed on a cyclical basis for both distribution and station assets. Maintenance intervals and procedures follow utility best practice and manufacturer recommendations. Where practicable, an inspection is performed during the maintenance activity, with results integrated into the ACA process. Corrective maintenance is deployed to improve and extend the condition of the asset and are executed when needed based on the findings and outcomes of the inspection and maintenance activities. Corrective maintenance activities include the repair or replacement of asset components that are found to be defective, inoperable, failing, or have already failed. Where feasible, to avoid public safety and reliability risks, corrective maintenance is completed on the spot when a deficiency is identified during inspections. For example, metal patches may be applied immediately to external cabinets of pad-mounted equipment to cover small holes caused by minor rusting identified during the inspection. Deteriorating assets for which corrective maintenance is not economically feasible are flagged for planned replacement. If immediate safety or reliability risk is identified, the asset is escalated to system control so that timely reactive replacement can be executed.

The inspection, testing, and maintenance programs contribute to reducing unplanned outages and extending asset life. These programs are necessary for understanding the lifecycle degradation of the asset and collecting condition factors for the ACA, which is a fundamental analytical component for identifying renewal investments. Table 5.3.3 - 2 provides an overview of the inspection, testing, and maintenance activities by asset type. Inspection, testing, and maintenance cycles may be shortened for an asset with increased safety, environmental, or reliability risks.

Table 5.3.3 - 2 Overview of Inspection, Testing, And Maintenance Practices

System	Asset	Activity	Current Cycle	Changes Since Last DSP
Overhead	Poles	Visual Inspection	Every 3 years	
		Wood Pole Testing	Every 3 years, for wood poles over 15 years old[76]	Previously for every 7 years until age 49, then every 5 years after. The frequency was revised to every 3 years, targeting only poles older than 15 years old
Overhead	Conductors and Line Hardware	Visual Inspection	Every 3 years	
		Vegetation Management	Every 3 years (at a minimum)	Operational Area Dependent, ranging 3-4 years
		Infrared (IR) Scanning	Every 3 years (at a minimum)	
		Insulator Washing	As required by condition	
Overhead	Switches	Visual	Every 3 years	
		Infrared (IR) Scanning	Every 3 years (at a minimum)	
		Load Interrupter Switch (LIS) Maintenance	Every 6 years	
Overhead	Pole-mounted Transformers	Visual Inspection	Every 3 years	
		Infrared (IR) Scanning	Every 3 years (at a minimum)	
Underground	Pad-mounted Transformers	Visual Inspection	Every 3 years	

[76] Based on the Climate Study and Alectra's custom analysis, certain poles are operating beyond their design capacity given the current Alectra Standards and the ongoing structural deterioration of said existing poles. Alectra will strengthen the overhead system by identifying and reinforcing poles at risk through more frequent testing. The pole testing cycle is standardized to a three-year interval across all regions. Every wood pole older than 15 years must have a valid test result within the past six years. Once this baseline is achieved, Alectra may re-evaluate testing frequency.

System	Asset	Activity	Current Cycle	Changes Since Last DSP
Underground	Submersible and Vault Transformers	Visual Inspection	Every 3 years	
Underground	Cable Accessories	Visual Inspection	Co-occurring with associated equipment.	
Underground	Switches	Visual Inspection	Every 3 years	
Underground	Switchgear	Visual Inspection	Every 3 years	
		Dry Ice Cleaning	Every 6 years for 13.8kV or less, Every 3 years for 27.6kV	
Underground	Civil Structures	Visual Inspection	Every 3 years	
Station	Power Transformers	Visual Inspection	Monthly	
		Oil Testing	Yearly	
		Infrared (IR) Scanning	Yearly	
		Doble	Every 6 years (at a minimum)	Changed from operational area dependent to every 6 years
		Tap Changer	Every 6 years	Changed from yearly to every 6 years
Station	Station Protection Relays	Visual Inspection	Monthly	
		Maintenance	Electromechanical every 6 years. Solid State and Microprocessor-based every 10 years	Previously operational area dependent
Station	Battery and Charger	Visual Inspection	Monthly	
		Testing	Yearly	

System	Asset	Activity	Current Cycle	Changes Since Last DSP
Station	Circuit Breaker	Visual Inspection	Monthly	
		Maintenance	Every six years	Previously operational area dependent
Station	Switchgear	Visual Inspection	Monthly	
		Maintenance	Every six years	
Metering	Wholesale Revenue Meters	Remote Performance Verification	Every 18 months	
		Reverification Testing	As per Measurement Canada testing requirements	
Metering	Wholesale Meter Instrumentation	Visual Inspection	Aligned with schedule for Measurement Canada testing requirements	
Metering	Retail Revenue Meters	Sample Reverification Testing	As per Measurement Canada testing requirements	

A Distribution Assets

The following section details the inspection, testing, and maintenance practices for distribution assets.

A.1 Pad-Mounted Transformers

Alectra Utilities inspects pad-mounted transformers on a 3-year minimum inspection cycle, which is aligned with OEB Appendix C Minimum Inspection Requirements with respect to urban infrastructure. Asset inspections provide Alectra Utilities with condition data to conduct an ACA to inform system sustainment strategies. The inspection includes checking for signs of oil leaks and corrosion. In addition, Alectra Utilities also performs corrective maintenance at the time of inspection, where feasible. This includes shifting cabinets back on the foundation, clearing vegetation, replacing locks, stickers, and nomenclature, patching holes, regrading, and repairing connections. Where corrective maintenance is not economically feasible or if the transformer is identified to be posing an immediate safety and reliability risk, Alectra Utilities will replace the transformer according to Figure 5.3.3 - 6.

A.2 Submersible and Vault Transformers

Alectra Utilities inspects submersible and vault transformers on a 3-year minimum inspection cycle, which is aligned with OEB's minimum inspection requirements with respect to urban infrastructure. Asset inspections provide Alectra Utilities with condition data to conduct an ACA to inform system sustainment strategies. In addition, Alectra Utilities performs corrective maintenance at the time of inspection. This includes unclogging drains and replacing locks, caution labels, and nomenclature. Corrective maintenance related to the transformer room infrastructure are identified to the customer to take necessary action.

A.3 Pole-Mounted Transformers

Alectra Utilities inspects pole-mounted transformers on a 3-year minimum inspection cycle, which is aligned with OEB's minimum inspection requirements with respect to urban infrastructure. Asset inspections provide Alectra Utilities with condition data to conduct an ACA to inform system sustainment strategies.

Alectra Utilities also targets a minimum of one-third of the overhead distribution plant for Infrared (IR) Scanning. Where warranted, a full system scan will be performed in addition to targeted scans on critical feeders or at critical points in the system, such as feeder egress from the station. IR scanning, also known as thermography, is on-condition monitoring of electrical equipment to identify anomalies and predict asset performance. Using IR radiometers, crews can visualize and quantify thermal anomalies associated with component deficiencies and predict equipment failure modes. More specifically, IR scanning reveals temperature variances (caused by excessive heat) in the equipment that can indicate an overloading issue, a bad connection, overheated or defective component. IR scanning covers all primary overhead lines (3 phase and 1 phase main lines and laterals), including all related components along the line (i.e. aerial transformers and associated equipment, insulators, load break disconnect switches, fused and solid blade disconnects, potheads, terminations, pothead switches, and reclosers). Table 5.3.3 - 3 illustrates the criticality and response time associated with the resulting temperature increase (compared to a particular reference point).

Table 5.3.3 - 3 IR Result and Recommended Response

Temp Difference	Criticality (to be listed on report)	Sub Cause Listing	Contractor Action	Type of Equipment	Internal Alectra Utilities Action
> 50 °C	Urgent (1)	Major heating anomaly; repair immediately	Call Alectra Utilities contact (Lines) and Document	Critical	Immediate repair
				Non-critical (secondary or fused)	Repair within one month
> 20 to 50 °C	Major (2)	Indicates deficiency; repair when time permits	Document	Critical	Repair within one month
				Non-critical (secondary or fused)	Repair within one year of detection
> 10 to 20 °C	Moderate (3)	Indicates probable deficiency; repair when time permits	Document		Repair within one year of detection
1 to 10 °C	Minor (4)	Possible deficiency; warrants investigation	Document		Investigate/ monitor. Compare with next cycle for deficiencies

A.4 Switchgear

Alectra Utilities inspects pad-mounted switchgear on a 3-year minimum inspection cycle, which is aligned with OEB's minimum inspection requirements with respect to urban infrastructure. Asset inspections provide Alectra Utilities with condition data to conduct an ACA to inform system sustainment strategies. In addition, Alectra Utilities also performs corrective maintenance at the time of inspection. This includes shifting cabinets back on the foundation, regrading, and replacing locks, stickers, and nomenclature.

Alectra Utilities also performs dry ice cleaning on a 6-year cycle for air-insulated switchgear on the 13.8kV and lower voltage systems, and on a 3-year cycle for air-insulated switchgear on the 27.6kV system because air-insulated components on the 27.6kV voltage level have a higher susceptibility to tracking and flashover events. Air-insulated switchgear are prone to tracking and failure due to the accumulation of contamination on insulating surfaces. Like insulators on overhead systems, it is best utility practice to clean the device to ensure continued life and operation. Dry ice cleaning is proven to be effective in removing contamination (such as salt and dirt) that contributes to tracking and flashover. Where warranted, targeted dry ice cleaning will be performed on vault room equipment if the need was identified from a visual inspection. During the dry ice cleaning process, a detailed inspection will also be carried out, which provides Alectra Utilities with condition data to conduct an ACA.

A.5 Overhead Switches

Alectra Utilities inspects overhead switches on a 3-year minimum inspection cycle, which is aligned with OEB's minimum inspection requirements with respect to urban infrastructure. Asset inspections provide Alectra Utilities with condition data to conduct an ACA to inform system sustainment strategies. In addition, Alectra Utilities also performs corrective maintenance at the time of inspection. This includes replacing missing or damaged nomenclature.

Alectra Utilities has also initiated a maintenance program involving the cleaning and replacement of components that will prolong the life of LIS switches. LIS Maintenance is considered a best utility practice due to the crucial function these switches provide in system operating flexibility and reliable power delivery to customers. The failure of an LIS to operate can lead to additional resource hours (i.e. due to the inability to operate the switch), and/or extended outage minutes to customers. During the LIS Maintenance process, a detailed inspection will also be carried out, which provides Alectra Utilities with condition data to conduct an ACA.

Alectra Utilities also targets a minimum of one-third of the overhead distribution plant for IR scanning (refer to *Section 5.3.3.2 A.3* for additional details).

A.6 Conductors and Line Hardware

Alectra Utilities inspects conductors and line hardware on a 3-year minimum inspection cycle, which is aligned with OEB's minimum inspection requirements with respect to urban infrastructure. Asset inspections provide Alectra Utilities with condition data to conduct an ACA to inform system sustainment strategies.

Alectra Utilities also trims vegetation encroaching to overhead conductors to maintain necessary clearance requirements. The vegetation management cycle will be harmonized to 3-year cycle across all regions for the DSP period. The program ensures a minimum horizontal and vertical clearance of three metres is maintained around overhead high-voltage primary lines wherever practical, while a one-metre clearance is enforced around overhead equipment and secondary infrastructure. In addition to proactive tree trimming, Alectra Utilities ensures that any dead, defective, or structurally weak tree branches with a reasonable risk of contacting overhead power lines are promptly removed. Hazard trees are reactively identified and removed to avoid unplanned outages due to tree contacts and risk of tree falling on overhead lines during adverse weather conditions.

Alectra Utilities also targets a minimum of one-third of the overhead distribution plant for IR scanning each year (refer to *Section 5.3.3.2 A.3* for additional details).

Alectra Utilities also performs insulator washing to prevent failures caused by tracking on high voltage overhead porcelain insulators. Overhead porcelain insulators are prone to contamination, especially due to road salt or other airborne contaminants which can result in tracking leading to pole fires and consequently to power interruptions. Alectra Utilities follows a condition-based approach based on field conditions to establish where insulator washing is required. Periodically, crews will inspect known high contamination locations to determine the level of contamination and trigger insulator washing requirements, where appropriate. In addition, insulator washing is completed if a need is identified through the visual inspection and maintenance activities for a particular area. Repeated failures due to insulator tracking or pole fires may also trigger spot insulator washing.

A.7 Poles

Alectra Utilities inspects poles on a 3-year minimum inspection cycle, which is aligned with OEB's minimum inspection requirements for urban infrastructure. Asset inspections provide Alectra Utilities with condition data to conduct an ACA to inform system sustainment strategies. If required, Alectra Utilities also performs corrective maintenance at the time of inspection. Corrective maintenance activities include replacing missing or damaged cable guards, guy guards, ground wires, and nomenclature.

Alectra Utilities also performs wood pole testing every 3 years for poles older than 15 years. Wood poles will be tested to determine remaining strength and the extent of pole degradation. The testing used for remaining strength is the resistograph test. The resistograph test involves four drill tests on each pole. The first drill is parallel to the ground at waist height and is used to measure the diameter of the pole. The second, third, and fourth drill tests are done at a 30-degree angle downward from the base of the pole and 120 degrees apart from each other, to measure the amount of decay and cavities inside the pole below ground level. Resistograph tests estimate the percentage of remaining strength of a wood pole. The percentage of remaining strength values are used in the ACA model in establishing the Health Index.

A.8 Cable Accessories

Alectra Utilities inspects cable accessories above ground, such as separable connectors (e.g. elbows) and cable terminations, on a 3-year minimum inspection cycle (e.g. pad-mounted switchgear) or where possible during inspections of other underground equipment on as needed based on risk (e.g. pad-mounted transformers). Asset inspections provide Alectra Utilities with condition data to conduct an ACA to inform system sustainment strategies. If required, Alectra Utilities also performs repairs as part of corrective maintenance at the time of inspection. Corrective maintenance pertaining to cable connectors or terminations includes replacing damaged cable connections, as well as repairing broken neutral and ground wires.

A.9 Underground Switches

Alectra Utilities inspects underground switches (for example, junction cubicles) on a 3-year minimum inspection cycle, which is aligned with OEB's minimum inspection requirements with respect to urban infrastructure. Asset inspections provide Alectra Utilities with condition data to conduct an ACA to inform system sustainment strategies.

A.10 Cable Chambers

Alectra Utilities inspects cable chambers on a 3-year minimum inspection cycle, which is aligned with OEB's minimum inspection requirements with respect to urban infrastructure. Asset inspections provide Alectra Utilities with condition data to conduct an ACA to inform system sustainment strategies. The inspection includes reviewing the condition of the vault cover for trip hazards and signs of deterioration and condition of the concrete walls and ceilings.

Other civil assets, including hand holes, splice pits, and secondary pedestals, are not included within the minimum 3-year inspection cycle.

B Station Assets

Alectra Utilities conducts monthly patrol inspections of every transformer and municipal station. This meets or exceeds OEB Appendix C Minimum Inspection Requirements which dictate that the maximum intervals are one month, six months, or one year, depending on the station configuration and location. Maintenance intervals are summarized in Table 5.3.3 - 2. The following section details the inspection, testing, and maintenance practices for station assets.

B.1 Power Transformers

Stations staff conduct in-depth visual inspections during monthly station patrols of all in-service power transformers, including their cooling system, bushings, and tap changer. Corrective maintenance for executing repairs is scheduled to address issues identified during these inspections. Power transformer planned maintenance activities are based on manufacturer's instructions and include the following activities: Oil testing, infrared scanning, Doble testing of the transformer and bushings, and tap changer maintenance. Activities associated with each are described in more detail.

Oil Testing: Power transformers undergo annual oil testing which includes Dissolved Gas Analysis (DGA) and oil quality analysis. Testing is done in accordance with IEEE 62-1995 IEEE Guide for Diagnostic Field Testing of Electric Power Apparatus Part 1: Oil-Filled Power Transformers, Regulators, and Reactors. Both DGA and oil quality are important diagnostic tools that are used to monitor the condition of the transformer. These tests detect insulation breakdown, water in the oil, stressing of the coils, and localized overheating and arcing that can lead to failure of the transformer. Currently, Alectra Utilities uses a third-party laboratory to carry out testing of oil samples. Laboratory analysis includes a comparison of results of previous transformer oil samples and detailed recommendations for the transformer.

DGA is also performed using portable equipment as well as through DGA online monitoring on some transformers. Online DGA equipment is used for continuous monitoring of transformer gas concentrations and can be used to send alerts at specific gas concentration thresholds. DGA data and alerts are transmitted through Supervisory Control and Data Acquisition (SCADA). DGA and oil quality tests identify abnormalities within the transformer and provide detailed information to support decision-making with respect to the future operation and maintenance of the transformer.

Doble Testing: Doble testing is typically conducted every 6 years and is used to assess the overall power factor, winding turns ratio, leakage reactance, and excitation current of the transformer. Doble testing is conducted in accordance with the Doble transformer maintenance and test guide. These tests detect moisture in the oil or insulation, detect contamination in the transformer bushing, determine the electrical insulation quality, and locate bad connections and winding movement. The Doble equipment provides test results in relation to expected values and thresholds. Doble testing may also be conducted following a transformer’s exposure to high currents during fault conditions.

DGA testing, and oil quality analysis complement each other to provide a clear indication of the overall health of the transformer.

IR Scanning: IR scanning at stations is typically conducted yearly and twice a year at some stations. Like the IR scanning of distribution assets, the scanning of components within a station assist in identifying components with temperature rise above normal. This alerts staff to components operating above normal values and flags an action item.

Tap Changer Maintenance: Planned oil-filled tap changer maintenance is typically conducted every six years. Planned maintenance activities include the following: Inspecting physical and mechanical condition, verifying proper operation, performing tests recommended by the manufacturer, and making any necessary adjustments or repairs.

B.2 Circuit Breakers

Stations staff conduct in-depth visual inspections of all in-service circuit breakers during monthly station patrols. Corrective maintenance is scheduled to address issues identified during these inspections. Planned circuit breaker maintenance is based on the manufacturer's recommendation and is typically scheduled every six years. Planned maintenance includes the following work: lubricate, clean, adjust, and align control mechanism, contact resistance measurement, and test tripping and closing circuits.

B.3 Switchgear

Stations staff conduct in-depth visual inspections of all in-service station switchgear during monthly station patrols. Corrective maintenance is scheduled to address issues identified during these inspections. Planned station switchgear maintenance is based on the manufacturer's recommendation and is typically scheduled every six years. Planned maintenance consists of the following work: busbar, enclosure, and insulator maintenance, checking and tightening connections, and checking and cleaning the enclosure.

B.4 Station Protection Relays

Stations staff conduct in-depth visual inspections of all in-service station protection relays during monthly station patrols. Corrective maintenance is scheduled to address issues identified during these inspections. Three types of protection relays are used to clear faults that occur in the distribution grid: electromechanical, solid state, and microprocessor-based. Maintenance performed on each type of relay and maintenance intervals are as follows:

Electromechanical Relays: Every six years, secondary injection tests are performed to verify the tripping time accuracy, and any necessary adjustments are made. Any required mechanical adjustments are also made.

Solid State Relays: Every ten years, secondary injection tests are performed to verify the tripping time accuracy, and any required adjustments are made. Since these electronic relays have no moving parts, there is no physical wear due to usage.

Microprocessor-based Relays: Every ten years, secondary injection tests are performed to verify the tripping time accuracy of the relays. Adjustment is typically not required since these relays do not drift. Since these electronic relays have no moving parts, there is no physical wear due to usage.

B.5 Batteries and Chargers

Stations staff conduct visual inspections of all in-service station batteries and chargers during monthly station patrols. Corrective maintenance is scheduled to address issues identified during these inspections. Annual battery and battery charger maintenance and testing consist of measuring and recording each battery unit voltage, measuring the charging current, and battery impedance testing. Impedance testing detects potential equipment failure by measuring the chemical and electrical effects that would indicate deterioration of the battery blocks. Readings outside of tolerance values indicate a potential failure which could result in a loss of station equipment control.

C Metering Assets

Alectra Utilities' activities related to wholesale revenue meters and retail revenue meters are described more broadly in the Network Metering program in *Appendix B06 - Network Metering (Section 3.1.1)* and *(Section 3.1.2).*

Meters are complex electronic devices that are primarily assessed by their age as compared to the manufacturer's recommended service life and trending of the asset failure rates. Alectra Utilities has more than one million meters throughout its service territory, and inspection is typically impractical due to the number of assets. Furthermore, the meters are sealed, and the process of individual assessment would be prohibitively expensive including: Cost of the removal of the meter in the field; shipping; testing and assessment in a Measurement Canada approved laboratory; repair if required and feasible; re-sealing as per regulations; re-shipping; and re-deployment.

Alectra Utilities adheres to regulations that govern the condition and accuracy of its revenue meters, including the *Electricity and Gas Inspection Act*[77]*,* W*eights and Measures Act*[78]*,* and the *IESO Market Rules*[79]. As per regulation, revenue meters must be maintained in good working condition and tested for accuracy on a schedule set by Measurement Canada for that specific meter form. Alectra Utilities maintains a Measurement Canada certified Meter Laboratory for the testing of its single-phase and polyphase retail meters and wholesale revenue meters.

5.3.3.3 Asset Replacement Practices

Alectra Utilities evaluates asset replacement needs through comprehensive assessment of failure events, failure risk from deterioration, functional obsolescence, and asset performance trends. Asset replacement practices ensure alignment with applicable standards, system capacity requirements, and accommodation of third-party requests, such as those for roadway improvements. Alectra Utilities' replacement strategies also need to reflect the overall risk profile of its diverse asset base and account for changing asset demographics.

Planned replacement is required when indicators, such as condition and failure rate or asset criticality, necessitate a proactive replacement before total failure occurs. For example, wood poles that exhibit major degradation undergo proactive replacement to prevent potentially catastrophic pole-down incidents, and underground primary feeders receive scheduled renewal to avoid unplanned disruptions that can impact reliability to unacceptable levels and costs more than planned replacements. Planned projects with like-for-current standards replacement options deliver additional benefits for meeting capacity upgrade needs and standardization. For example, Alectra Utilities has standardized the sizing of residential transformers to 100kVA to support growing Electric Vehicles (EV) proliferation and avoid premature failure (or needed replacement) of undersized transformers in future.

In contrast, Alectra Utilities employs a reactive replacement strategy to address assets that have failed or pose a risk of imminent failure, safety, or environmental concerns. The decision to run to failure and address replacement reactively also considers reliability impact and availability of spare units or components. Reactive replacements occur outside the utility's control and often

[77] Electricity and Gas Inspection Act R.S.C., 1985, c. E-4
[78] Weights and Measures Act R.S.C., 1985, c. W-6
[79] Market Rules for the Ontario Electricity Market, May 1 2025

require crew mobilization at overtime or premium rates when performed outside of normal business hours. As a result, reactive work can be more expensive than planned replacements for certain categories of assets. Furthermore, due to lack of integrated planning and scheduling of work execution, reactive replacements can take longer to coordinate and complete. The extended duration of restoration further increases costs and impact to customers. For more details on reactive capital investment drivers and portfolio strategy, refer to *Appendix B05 - Reactive Capital*.

Table 5.3.3 - 4 summarizes Alectra Utilities' asset renewal strategies for each asset class.

Table 5.3.3 - 4 Summary of Asset Renewal Strategies for 2027 to 2031 DSP Period

Asset Class	Primary Renewal Strategy	Comments
Distribution-Class Pad-Mount, Pole Mount and Vault Transformers	Planned and Reactive	Alectra Utilities follows a planned replacement strategy to manage the at-risk transformer population to avoid public safety risks, environmental risks (e.g. PCB contamination in the event of an oil leak), and prolonged customer interruption risks. However, Alectra Utilities reactively replaces units when they fail, leak oil, or pose an immediate safety risk. Refer to *Section 5.3.3.3 A.1.*
Pad-Mounted Switchgear	Planned and Reactive	Alectra Utilities targets air-insulated switchgear and first-generation solid-dielectric switchgear for planned replacement due to a known risk of flash-over events leading to failure. In addition, Alectra Utilities will replace leaking SF_6 and oil-insulated switchgear that pose risks to safety and/or the environment. Refer to Section *5.3.3.3 A.2.*
Overhead Load Interrupter Switches (LIS)	Planned and Reactive	Alectra Utilities manages replacement of overhead LIS switches through proactive and reactive replacement. Switches will be replaced in a planned manner based on condition. Refer to Section *5.3.3.3 A.3.*
Overhead Primary Conductors	Planned	Alectra Utilities targets #6 and smaller overhead primary conductor for planned replacements due to historical failures associated with this conductor type. The replacement of other primary conductors takes place in conjunction with line rebuild investments. Refer to Section *5.3.3.3 A.4.*

Asset Class	Primary Renewal Strategy	Comments
Wood and Concrete Poles	Planned	Alectra Utilities' strategy for pole replacement is driven primarily by pole condition. Prioritization of pole replacements is based on risk and criticality, in compliance with CSA requirements. Refer to Section *5.3.3.3 A.5.*
Underground Cables and Accessories – Primary Paper Insulated, Lead Covered (PILC) Cables	Planned and Reactive	PILC cable that is determined to be in 'Very Poor' condition (e.g. exceeds End of Useful Life of 70 years) and is critical to the reliability of the system, will be replaced proactively with ethylene propylene rubber-insulated (EPR) cable. Similarly, in the event of failure, PILC cables will be removed and replaced with EPR cable. Refer to Section *5.3.3.3 A.6.1.*
Underground Cables and Accessories – Primary Ethylene Propylene Rubber-Insulated (EPR) Cables	Reactive	Alectra Utilities' population of EPR cables is relatively new, with none exceeding 15 years in age. Alectra Utilities' current practice is to repair or replace EPR cables reactively upon failure. Refer to Section *5.3.3.3 A.6.2.*
Underground Cables and Accessories – Primary Cross-Linked Polyethylene (XLPE) Cables	Planned and Reactive	Alectra Utilities implements two types of strategies in managing its XLPE cable population: (i) cables that are deteriorated will undergo planned replacement; and (ii) cables which are less than 35 years of age will be considered for cable rehabilitation. However, the population of cables that can be injected is decreasing such that it is not viable to continue this strategy beyond 2029. If a cable fails while in service, Alectra Utilities will repair the cable by splicing out the faulted segment. Refer to Section *5.3.3.3 A.6.3.*
Utility Chambers and Equipment Foundation Vaults	Planned	Alectra Utilities undertakes the planned replacement or refurbishment of utility chambers and equipment foundations based on relevant condition information (as determined through inspections). If material asset degradation is identified, Alectra Utilities will execute refurbishment or replacement depending on the extent of the deterioration. Refer to *Section 5.3.3.3 A.7.1*.

Asset Class	Primary Renewal Strategy	Comments
Fault Indicators	Planned and Reactive	Alectra Utilities plans to: (i) Install new fault indicators in parts of the distribution system where fault indication is lacking. (ii) Replace older fault indicators that are technologically obsolete and prone to malfunction. Refer to *section 5.3.3.3 A.7.2.*
Insulators	Planned	Insulator replacements are targeted at replacing legacy porcelain and first-generation polymer insulators in the distribution system. Refer to *Section 5.3.3.3 A.7.3.*
Low Voltage Secondary Cables (Overhead and Underground)	Planned and Reactive	The replacement of low voltage secondary cables and conductors is bundled as part of planned rebuild projects. Upon failure, these cables and conductors are replaced or repaired reactively. Refer to *Section 5.3.3.3 A.7.4.*
Submersible Load Break Device (LBD) Switches	Reactive	Alectra Utilities primarily manages its submersible LBD switches through reactive replacement. However, units that are no longer functioning as intended and no longer receive vendor support (e.g. VACpac units) will be targeted for planned replacement. Refer to *Section 5.3.3.3 A.7.5.*
Power Transformers	Planned	Alectra Utilities plans its power transformer replacements based on HI assessment (i.e. oil quality, dissolved gas analysis, and other condition-related information), input from stations SMEs, and integrated planning considerations. Refer to *Section 5.3.3.3 B.1*.
Station Circuit Breakers	Planned	Alectra Utilities plans its circuit breaker replacements based on HI assessment, incorporating condition-based information, input from stations SMEs, and integrated planning considerations. Refer to *Section 5.3.3.3 B.2.*
Station Switchgear	Planned	Alectra Utilities plans its switchgear replacements based on HI assessment, incorporating condition-based information, input from stations SMEs, and integrated planning considerations. Refer to *Section 5.3.3.3 B.3*.

Asset Class	Primary Renewal Strategy	Comments
Protection and Control Systems	Planned	Alectra Utilities plans its protection and control systems replacements either in coordination with replacements of other station assets or as independent investments. Independent investments that are driven by condition, as determined by failure, maintenance, and repair history, are categorized as Substation Renewal investments. Those investments that are driven by a need for additional functionality or to support other systems are categorized as System Service investments. Refer to Section *5.3.3.3 B.4.*
Retail Revenue Metering	Reactive, Planned	To ensure accurate customer billing, Alectra Utilities must replace its retail revenue meters reactively as they fail. When the asset failure rates trend beyond what can be practically and cost effectively managed reactively, retail meters are planned for replacement as a network. Alectra Utilities' retail revenue failure rates and planned replacement strategy are provided in *Appendix B06 – Network Metering (Section 3.1.4)* and *(Section 3.1.5).*
Wholesale Revenue Metering	Planned Reactive	Alectra Utilities uses largely planned replacement approach for the replacement of its wholesale revenue meters, based primarily on the age of the asset. The strategy is secondarily driven by regulatory compliance with the IESO Market Rules and Measurement Canada regulations. Wholesale revenue meters are replaced reactively where measurement inaccuracies are identified or when a total failure occurs. For more information, refer to *Appendix B06 – Network Metering (Section 3.1.1)*.

A Distribution Assets

The following subsections detail Alectra Utilities' asset renewal drivers and the applicable practices across the following distribution asset classes:

- Distribution transformers
- Distribution switchgear
- Overhead switches
- Overhead conductors

- Poles (Wood and Concrete)
- Underground primary cables

The ACA relies on the findings from the distribution inspection, testing, and maintenance activities detailed in *Section 5.3.3.2 A*.

A.1 Transformer Renewal

Distribution transformers are a vital component to servicing customers from the distribution system at various utilization voltages. Distribution transformers consist of three main installation types: Pad-mounted, pole-mounted, or housed within a vault (e.g. submersible transformers).

Alectra Utilities' asset management strategy for distribution-class transformers follows a planned approach. Alectra Utilities will pursue planned replacement if there is risk of the following:

i. **Public injury:** A deteriorated transformer (i.e. categorized as "Poor" or "Very Poor" in the ACA), as summarized in *Chapter 5.3.2 (Section 5.3.2.2 A.1.1),* posing a risk to public or employee safety (e.g. corroded or damaged physical structure and compromised enclosure of energized components). Refer to Figure 5.3.3 - 5 for an example of a compromised enclosure.

Figure 5.3.3 - 5 Compromised Transformer Enclosure Posing Public Safety Risk

ii. **Environmental contamination**: A deteriorated transformer is at risk of environmental contamination and remediation (e.g. showing signs of leaking oil). From 2021 to 2024, the average environmental remediation cost due to leaking oil was $50,000 per site. Replacing deteriorated transformers using a planned strategy will avoid the environmental risk of oil contamination and avoid environmental remediation costs associated with reactive capital replacement. Transformers that contain known PCB concentrations of 2 parts per million (ppm) or more, or unknown concentrations but manufactured prior to 1984 (i.e. at-risk of containing more than 2 ppm PCB) are also targeted for planned replacement[80]. Leaking PCBs in the environment can lead to bioaccumulation, presenting serious health risks for humans and wildlife. Under the PCB Regulations (SOR/2008-273), Alectra Utilities is required to report any spills involving more than one gram of PCB into the environment and complete a full environmental remediation.

iii. **Customer interruption:** A transformer that poses a high risk of failure or prolonged outage due to their condition, functional obsolescence (e.g. overloaded transformers that are undersized for the customer's demand), or location (e.g. inaccessible and complex installations).

As part of Alectra Utilities' inspection and maintenance program, where possible, corrective maintenance is performed to address concerns and extend the useful life of the transformers, as detailed in *Section 5.3.3.2*.

[80] Any transformer identified with a PCB concentration of 50 ppm or greater is replaced by Alectra Utilities by the end of the calendar year in which it is identified. All such units will be removed from service no later than December 31, 2025, in accordance with the PCB Regulations (SOR/2008-273).

Figure 5.3.3 - 6 demonstrates Alectra Utilities' general approach for prioritizing deteriorated transformers, including transformers posing a prolonged customer interruption risk.

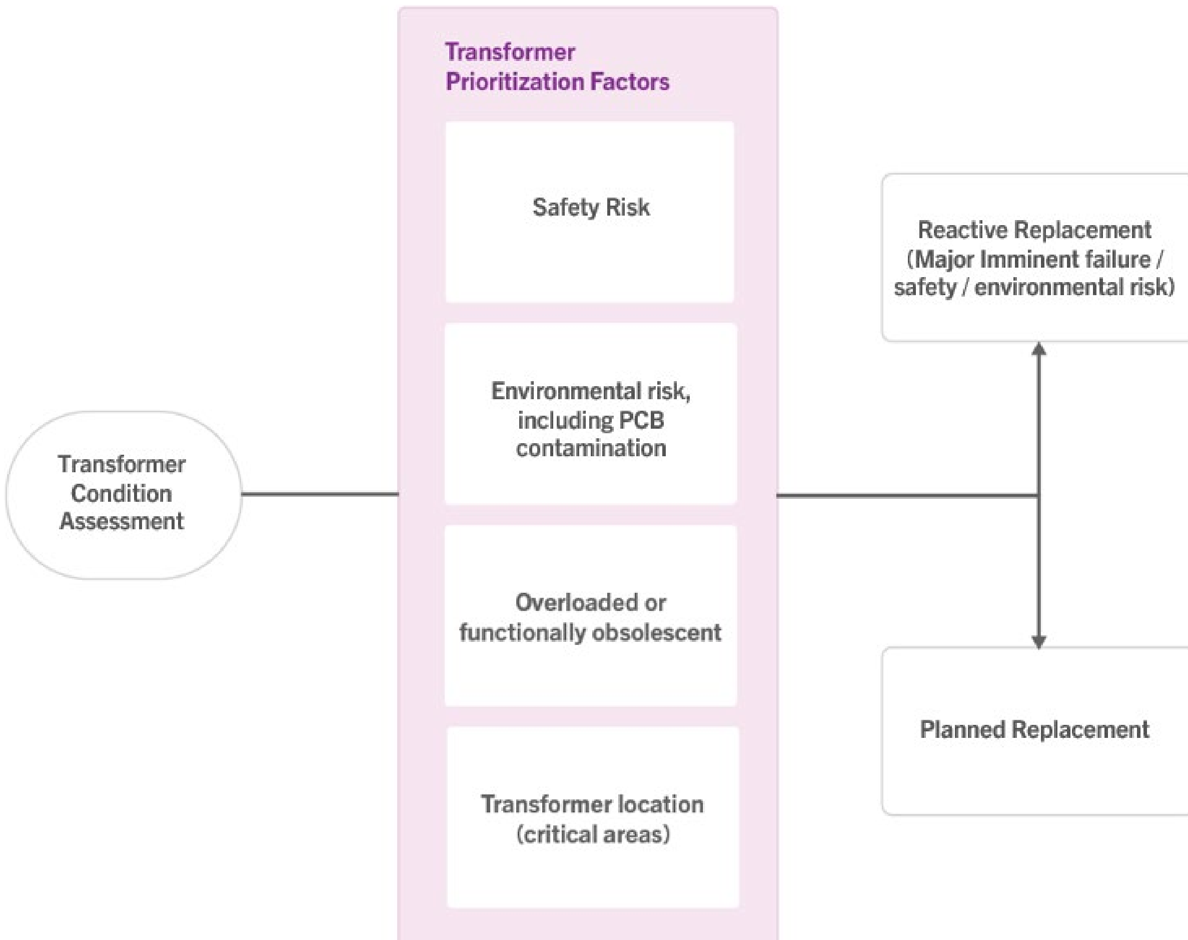


Figure 5.3.3 - 6 Transformer Sustainment Priority Action

Figure 5.3.3 - 6 demonstrates that Alectra Utilities' priority is addressing deteriorated transformers for planned replacement. This includes units that are showing signs of an oil leak, contain PCB, or are compromised (e.g. due to corrosion), posing safety risks to the public. Oil leaks, especially when the oil leak is active, risk spilling onto the road or into waterways (e.g. catch basins or ditches). It is imperative that these types of situations, including assets with immediate safety or asset failure risks, are addressed reactively to avoid environmental contamination and remediation, undue safety hazards, and prolonged outages.

Another source of planned replacements for transformers stems from Alectra Utilities' assessment of transformers that are frequently subjected to loading beyond their nominal rating. Alectra Utilities routinely performs transformer loading analysis to identify these overloaded units as potential replacement candidates. Alectra Utilities also considers a unit's condition and physical location (i.e. in terms of potential access restrictions). For example, if a transformer is in a difficult-to-reach location (e.g. rear-lot configuration) such that its failure would result in a lengthy repair process and customer outage, then the unit is more likely to warrant planned replacement. In addition, if through inspections and normal operating activities, Alectra Utilities identifies obsolete transformers that are no longer supported by standard inventories, then those transformers will be evaluated for planned replacement. Failure of larger three-phase distribution transformers supplying commercial or industrial customers can lead to significant service reliability impacts, potentially halting customer production capability. Alectra Utilities plans such transformer replacement as the transformer approaches end-of-life or where frequent overloading is identified. For transformers where overloading is the driver for intervention, the replacement transformer would be sized accordingly.

The replacement practices described above help minimize long term costs and risks to Alectra Utilities' customers. Transformer investment pacing options are discussed in *Appendix B03 - Transformer Renewal*.

A.2 Switchgear Renewal

Distribution-class pad-mounted switchgear are used in the underground distribution system to facilitate the connection of local distribution circuits to main line underground feeder cable systems as well as interconnecting main line feeder circuits. Switchgear are critical components in the distribution system that help reduce the impact of an outage or maintenance activity and improve service reliability. Switchgear units are used for isolating, sectionalizing, and fusing for laterals, as well as for reconfiguring cable loops for maintenance, restoration, and other operating requirements. They enable providing service to residential subdivisions and commercial/industrial customers via fused connections to main feeder cable systems. A single switchgear can impact as many as 5,000 customers.

Alectra Utilities' asset management strategy for distribution-class pad-mounted switchgear follows a proactive approach due to the significant impact a switchgear failure has on safety, reliability, and the environment. Alectra Utilities' replacement strategy for pad-mounted switchgear focuses on the following four key aspects:

i. **Safety risk**: A switchgear is showing major degradation (i.e. categorized as "Poor" or "Very Poor" in the ACA), as summarized in *Chapter 5.3.2 (Section 5.3.2.2 A.1.2),* posing a risk to public or employee safety (e.g. exposed energized parts due to corrosion or risk of fire)
ii. **Premature failure risk**: 25kV air-insulated "live front" switchgear and first-generation solid-dielectric switchgear
iii. **Environmental risk**: Oil-leak (i.e. specific to oil-insulated units) and SF_6 leaks (i.e. specific to gas-insulated switchgear)
iv. **System design reconfiguration**: When switchgear requires replacement, units located within the scope of planned projects (e.g. rebuilds) will be assessed to determine whether they can be eliminated from the system altogether via design re-configuration. If this is not a feasible option, the switchgear replacement may be scheduled as part of the execution of the planned project.

As part of Alectra Utilities' inspection and maintenance program, where possible, corrective maintenance is performed to address concerns and extend the useful life of the distribution switchgear, as detailed in *Section 5.3.3.2*. In some cases, pad-mounted switchgear units are found to contain defects that affect a specific component within the unit and that do not compromise the entire unit. Based on an evaluation of the defects and associated cost-benefit analysis, Alectra Utilities determines whether targeted repair is appropriate. Typical defects that can be addressed through repair (rather than asset replacement) include damaged fuse holders, barriers boards affected by prolonged corona exposure, and cracked support insulators in air-insulated switchgear.

Alectra Utilities has identified two groups of switchgear (25kV air-insulated "live front" switchgear and first-generation solid-dielectric switchgear) that are prone to premature failure, posing significant safety and reliability risks due to their condition, design, and installation practices:

- <u>25kV air-insulated "live front" switchgear</u>: The useful life of air-insulated pad-mounted switchgear is between 20-45 years, with a typical useful life of 35 years when operating within a normal continuous rated operating voltage of 25kV.[81] Air-insulated switchgear uses porcelain insulators and air to insulate live components from ground. Air-insulated switchgear units have been failing prematurely due to the operating requirements of Alectra Utilities' underground distribution system. The air insulated switchgear units were manufactured to specification of normal continuous rated operating voltage of 25kV and tested to operate as high as 28kV to ensure operation at 27.6kV distribution voltage. These tests consider operational voltage of 28kV, but they do not consider the long-term lifecycle impacts of operating the asset at higher voltages in external environments with the presence of moisture and contamination. Environmental factors in southern Ontario have also led to earlier failure of these switchgear. While these units function relatively well in dry environment jurisdictions, the southern Ontario environment presents many challenges that cause units to fail. High humidity, condensation from changing temperatures and water in the below-grade foundations, when mixed with dirt and road dust, contribute to the formation of conductive paths on the insulating components. Over time, this ultimately reduces the insulating properties and leads to flashover and failure of the switchgear.

- First-generation solid-dielectric switchgear: While solid-dielectric switchgear is relatively new (started to adopt at scale approximately 12 years ago), Alectra Utilities has noticed issues with several manufacturers' first-generation versions of this switchgear. While current generation solid-dielectric switchgear has resolved these design issues, Alectra Utilities continues to experience premature failures with first generation units since the manufacturer defects impact the long-term life expectancy of the units.

Alectra Utilities has identified two groups of switchgear (oil-insulated switchgear and SF_6-insulated switchgear) that are prone to oil and gas leaks, posing significant safety and environmental risks. According to the 2023 ACA, nearly one-third of the switchgear asset base fall under these two groups, as illustrated in Figure 5.3.3 - 7. Further details on asset inventory are described in *Chapter 5.3.2 (Section 5.3.2.2 A.1.2)*.

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[81] Kinectrics Inc., "Asset Depreciation Study for Use by Electricity Distributors" (EB-2010-0178), July 8, 2010.

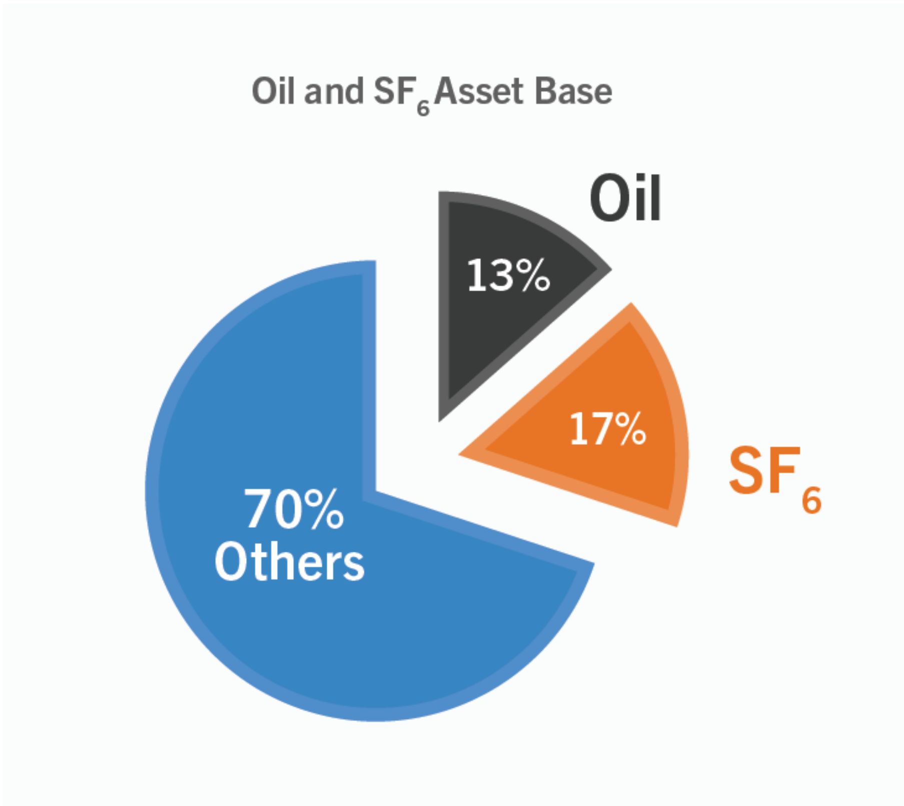

Figure 5.3.3 - 7 Breakdown of Oil-Insulated and Gas-Insulated Switchgear

- Oil-insulated switchgear: Alectra Utilities has 465 oil-insulated switchgear in its underground distribution system. As the name suggests, these units are filled with oil (over 1,500 liters in a typical unit), which operates as the switchgear's insulating medium. When these units fail, the oil can ignite and cause a fire, creating public and workers' safety risk. Figure 5.3.3 - 8 shows the result of a typical failure of an oil-filled switchgear. Many of these units are installed in public places and adjacent to customers' homes. Although the switchgear's oil tanks are sealed, condensation of water vapor can lead to contamination of the oil (which occurs over time) and can eventually lead to failure. In addition to the public and worker safety risks posed by potential oil ignition and fire, oil leaks and environmental cleanup may be required and can be costly to remediate.

Figure 5.3.3 - 8 Failed Oil-Filled Switchgear

- SF$_6$-insulated switchgear: Alectra Utilities has 571 SF$_6$-insulated switchgear in its underground distribution system. In the context of greenhouse gas emissions, SF$_6$ has an equivalent effect of 23,500[82] times that of carbon dioxide (CO_2); one kilogram of SF$_6$ has the same greenhouse effect of 23.5 tons of CO_2. While SF$_6$ is non-toxic in its pure form, gas leaks in large quantities in an enclosed space can displace oxygen, becoming a suffocation risk. Alectra Utilities replaces leaking SF$_6$-insulated switchgear on a reactive basis. Leaks or suspected leaks may be found through inspection, during operating procedures, or through SCADA where remote monitoring is available. Distribution switchgear manufacturers provide field service, which involves inspecting the unit and topping up the unit with SF$_6$ gas if the unit is verified to not be leaking. If a unit is confirmed to be low on gas and leaking, Alectra Utilities will replace the switchgear and send the removed unit for refurbishment, if eligible.

Based on the above areas of focus, Alectra Utilities' switchgear replacement strategy includes the elimination of all "Poor" and "Very Poor" assets (summarized in *Chapter 5.3.2 (Section 5.3.2.2 A.1.2))*, 27.6kV air-insulated switchgear, first-generation solid-dielectric switchgear, and oil-

[82] IPCC AR5

insulated switchgear. Alectra Utilities will proceed with a replacement strategy based on the system operating voltage, as explained below.

- For switchgear operating at 27.6kV, units will be replaced with standard 38kV rated solid-dielectric unit or units insulated with sulfur hexafluoride (SF_6)
  - Alectra Utilities plans to install solid-dielectric switchgear where possible instead of SF_6 insulated units. SF_6 units will still be required due to fault rating limitations of solid-dielectric switchgear (i.e. solid-dielectric supports a max fault rating of 12.5kA).
- For switchgear operating at 15kV or lower, Alectra Utilities will utilize 27.6kV rated air-insulated units for replacements, which are expected to perform reliably when operated at 15kV or lower.

Switchgear investment pacing options are discussed in *Appendix B02 - Underground Asset Renewal*.

A.3 Overhead Switch Renewal

Overhead switches serve as the primary method for switching loads for system operation and to restore customers after an outage. Overhead switches also enable Alectra Utilities to sectionalize and isolate parts of the distribution system as required. The main switch types in Alectra Utilities' distribution system include SF_6, solid-dielectric insulated units with vacuum interrupters and air-insulated load interrupters. These types of switches are referred to as Load Interrupter Switches (LIS).

Alectra Utilities' asset sustainment strategy for overhead switches is a proactive approach due to the significant impact an overhead switch has on reliability. Alectra Utilities replaces overhead switches identified to be in "Poor" or "Very Poor" condition (summarized in *Chapter 5.3.2 (Section 5.3.2.2 A.1.3))* according to the ACA. An example of a deteriorated switch is shown in Figure 5.3.3 - 9. When evaluating replacement options and timing, Alectra Utilities considers other factors, such as the location of the switch in relation to overhead rebuild initiatives and road authority requests for asset relocations. Certain minor defects can be repaired at relatively low costs to extend the life of the switch, as outlined in *Section 5.3.3.2*. Examples of repairs include missing rain caps, pitted contacts, faulty arc suppressors, misaligned switch blades, and binding linkages.

Figure 5.3.3 - 9 Mississauga – Melted Contacts on Switch

In addition to replacing deteriorated switches, Alectra Utilities also targets switches that are not fit for operation, either because they are functionally obsolete, no longer operable, or otherwise incapable of interrupting the load current (which is the primary function of a switch).

In numerous cases, the new switch will be capable of remote operation and automation, which will have the benefit of reducing outage times for customers. Alectra Utilities may replace overhead LIS units with automated high-speed circuit reclosures, depending on the location of the LIS in relation to normal system open points. Switch locations with high operating counts will also be considered for automation to improve switching response time and reduce the requirement to dispatch a crew to operate a switch. Normal system open points are identified pursuant to control room processes and are positioned to balance the loading on feeder circuits. This approach enables load transfer from one circuit to the opposite circuit at the normally-open point if one circuit experiences loss of power. Automation of switches at these normal open points will reduce service restoration response time and minimize the requirement to dispatch a crew to operate the switch at the open point.

Detailed discussions regarding the options analysis and pacing of the switch replacement investment is provided in *Appendix B01 - Overhead Asset Renewal*.

A.4 Overhead Conductor Renewal

Alectra Utilities' distribution system contains overhead conductors that exist in many various sizes and vintages. Certain sized legacy conductor types have demonstrated an elevated risk of failure, and experienced failures that led to dangerous "wire-down" incidents. The conductor types involved include vintage #6 wire gauge or smaller. These conductors typically remain in-service from older, lower voltage primary systems (e.g. 4.16kV and 8.32kV) and are currently considered undersized when compared to present-day standards. Due to the physical properties of this conductor type and the cyclic nature of loading, these conductors become brittle over time and can fail at junctions where conductors are supported or terminated. Due to their overhead configuration, these conductors are exposed to weather events such as wind and ice loading, which further increase their probability of failure.

Alectra Utilities proactively replaces deteriorated and undersized overhead conductors (summarized in *Chapter 5.3.2 (Section 5.3.2.2 A.1.4))*. Undersized primary conductors (i.e. #6 or smaller) represent a significant risk to the public and Alectra Utilities' crews. Most undersized conductor replacements will be carried out in conjunction with planned conversions of vintage 4.16kV and 8.32kV systems, which contain most of these conductor types. Alectra Utilities pursues targeted replacement of undersized conductors at locations that are outside the scope of near-term voltage conversion projects. Failure to replace deteriorated overhead conductors may lead to wire-down events, posing significant safety risks to the public. Figure 5.3.3 - 10 shows a broken wire due to undersized conductor. Undersized overhead conductors, such as #6 copper, has also been identified as a public safety risk by the Electrical Safety Authority (ESA) (refer to *Appendix B01 - Overhead Asset Renewal* for details).

Figure 5.3.3 - 10 Hamilton – Fallen Undersized Wire

A.5 Pole Renewal

Wood and concrete poles support Alectra Utilities' overhead distribution plant, including 18,463 kilometers of primary conductors (summarized in *Chapter 5.3.2 (Section 5.3.2.2 A.1.5))*, transformers, switches, streetlights, and telecommunication attachments, and are critical to enable the delivery of electricity to customers. The combination of severe weather, along with reduced strength (identified during field testing and visual inspection), can lead to failure scenarios where multiple poles lose their structural integrity and fail, likely falling to the ground. Restoring power to customers in this scenario may take up to 12 to 24 hours, depending on severity of the event. It is imperative that Alectra Utilities monitors and assesses the condition of the poles to avoid significant safety and reliability risks with prolonged outages.

Alectra Utilities' asset sustainment strategy for wood and concrete poles follows a proactive approach due to the significant impact a pole failure has on safety and reliability. Alectra Utilities' replacement strategy for poles focuses on the following three aspects:

- **Safety**: A pole indicating major degradation (i.e. categorized as "Poor" or "Very Poor" in the ACA), as summarized in *Chapter 5.3.2 (Section 5.3.2.2 A.1.5)*, posing a significant risk to public or employee safety (e.g. severe ground line rot or failed pole remaining strength test), where the pole may fall to the ground if not replaced. Alectra Utilities collects condition attributes that contribute to the Health Index. The condition attributes are captured from visual inspections (applicable to wood and concrete poles) or pole testing (applicable to wood poles). Pole testing is completed using a resistograph test to assess the remaining wood fibre strength. According to Canadian Standards Association (CSA) Standard C22.3 No. 1-10, "when the strength of a wood pole structure has deteriorated to 60% of the required design capacity, the structure shall be reinforced or replaced"[83]. Replacing fallen poles is a complex and time-intensive process, requiring crew members to safely remove debris and install new poles and conductors. Proactively replacing these at-risk poles leads to a more cost-efficient remediation process than reactive replacement, with less impact to customers and the public.

- **Storm hardening**: Adverse weather has been a significant contributor to sustained outages. Conditions such as high winds, heavy rain and snowstorms can damage overhead infrastructure, leading to prolonged outages. Alectra completed a Climate Risk and Vulnerability Assessment, which is discussed in *Chapter 5.3.2 (Section 5.3.2.1 C).* Climate projections indicate that high wind events will increase in frequency, severity and intensity across Alectra Utilities' service territory. As a result, both the climate-vulnerability status of each pole, and the locational wind severity risk (informed by the climate vulnerability study detailed in *Chapter 5.3.2 (Section 5.3.2.1 C)* are used to further prioritize replacement of deteriorated poles. Alectra Utilities must mitigate public safety risks, maintain system reliability, and account for customer preferences (refer to *Exhibit 1, Tab 5, Schedule 2 Application-Specific Customer Engagement)* to ensure that the distribution system is resilient to adverse environmental events. Replacing poles in susceptible and vulnerable areas (e.g. rear-lot configurations) with current standards will improve resilience to adverse weather and avoid the risk of pole failure due to high wind events. This methodology is in keeping with the OEB's Vulnerability and Storm Hardening (VASH) project, whereby Alectra Utilities has targeted poles deemed most at-risk due to climate perils identified through the climate study.
- **Location and equipment attachments**: Poles located in proximity to highways, railways, and river crossings, as well as poles that are currently supporting

[83] "Overhead Systems", CSA C22.3 No. 1-10, Clause 8.3.1.3, Canadian Standards Association.

transformers, switches, or telecommunication equipment, are prioritized for replacement due to the impact the pole failure will have on the system as well as potentially more complex replacement conditions involved due to these locations.

Figure 5.3.3 - 11 illustrates Alectra Utilities' approach for prioritizing deteriorated poles.

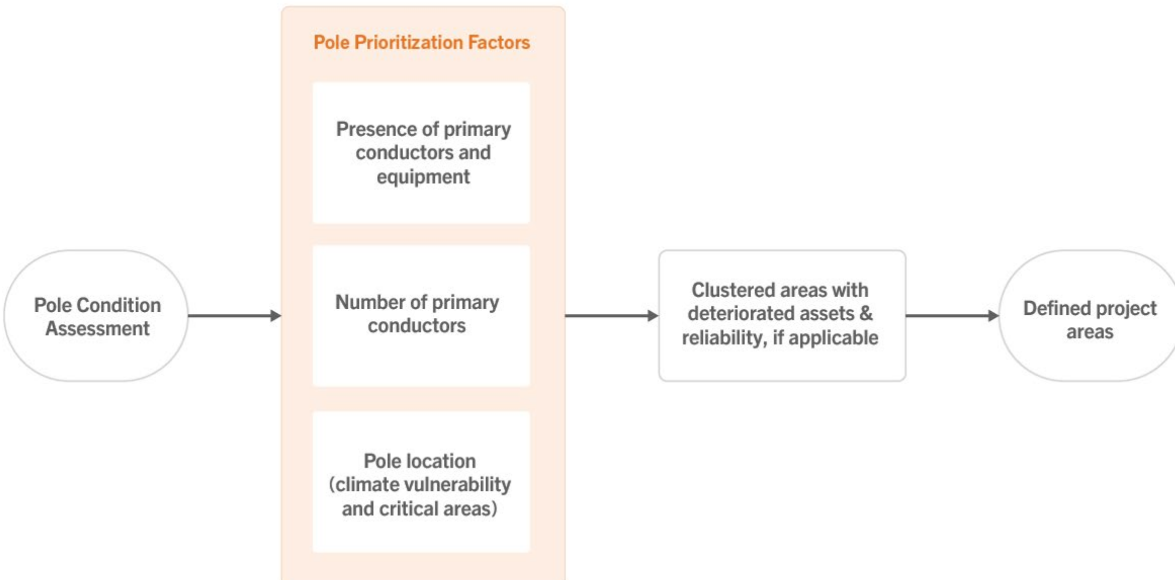

Figure 5.3.3 - 11 Pole Replacement Prioritization Factors

Using HI and considering other key aspects, such as pole location and its climate vulnerability, enables Alectra Utilities to target critical areas to avoid public safety and reliability risks. Detailed discussions regarding the options analysis and pacing of the Pole Renewal investments are provided in *Appendix B01 - Overhead Asset Renewal*.

A.6 Underground Cable Renewal

Alectra Utilities owns and operates 23,694 kilometers of underground primary cable, as summarized in *Chapter 5.3.2 (Section 5.3.2.2 A.1.6)*, including paper-insulated lead-covered (PILC) cable, ethylene propylene rubber-insulated (EPR), and cross-linked polyethylene (XLPE) cable. XLPE cables are categorized by the following types:

- Non-Tree-Retardant Cables (NON-TR)
- Tree-Retardant Direct-Buried Cables (TR-DB)

- Tree-Retardant or Strand-Blocked In-Duct Cables (TR-ID)

Primary underground cables are critical to the delivery of electrical service across Alectra Utilities' service territory. Underground distribution cables are commonly utilized in urban areas, where it is beneficial over overhead infrastructure for increased reliability and safety considerations. Insulation failure is a primary cause of faults on these cables. Faults on primary underground cables are usually caused by insulation failure within a localized area. Cable faults, especially in urban areas, are commonly found in challenging locations (e.g. under customer driveways or under decks in customer backyards), leading to prolonged outages to repair the cable.

To manage the lifecycle of underground primary cable, Alectra Utilities uses cable performance data (e.g. failure rates and customer outage impacts) in conjunction with cable Health Index results (summarized in *Chapter 5.3.2 (Section 5.3.2.2 A.1.6)*) to identify risk and accordingly plan cable renewal investments. Alectra Utilities completed an ACA for primary underground cable using HI models configured for each cable type. The risks and cable renewal strategies are discussed in *Section 5.3.3.3 A.6.1* to *Section 5.3.3.3 A.6.3*.

<u>A.6.1 PILC Cable</u>

PILC represents 2% of Alectra Utilities' primary cable population. PILC cables are hermetically sealed with a lead sheath, protecting the cable from humidity and outside elements. These cables can be constructed with a single conductor or multiple conductors. In Alectra Utilities' service territory, a majority of the PILC cables contain three conductors and are typically installed in a 3.5-inch duct. Long term degradation mechanisms of PILC cables include corrosion of the lead sheath and dielectric degradation of the oil impregnated paper insulation, leading to insulation breakdown and localized failures. When PILC cable fails, the faulted portion is removed, and the remaining functional cables are spliced through and returned to service.

Due to obsolescence, operational challenges with installation and reactive repair, and high renewal cost with limited suppliers available, Alectra Utilities replaces PILC cables with EPR. Alectra Utilities' current practice is to repair PILC cables reactively upon failure. When replacing failed PILC cables (part of a planned project), Alectra Utilities replaces the faulted cable segment with three equivalently rated EPR cables in existing duct, provided that the existing duct has minimum diameter of 3.5 inches. Where this minimum diameter cannot be met, or if the duct is no longer useable (e.g. collapsed or damaged), the entire duct and utility chamber system will be rebuilt and the end-of-life PILC cables will be replaced with the larger diameter standard XLPE cable. The challenge associated with this reactive replacement approach is lack of public right-of-way space where the PILC cables are currently installed (e.g. along congested streets in the western part of Alectra Utilities' service territory). Hence, Alectra Utilities will continue to monitor PILC cable failures to inform future planned replacement for this cable type.

PILC cable will be proactively replaced with EPR cable as a by-product of certain project coordination efforts. For example, Alectra Utilities plans to remove PILC cable during the Light Rail Transit (LRT) project in Hamilton's downtown core and during voltage conversion projects across Alectra West. Furthermore, PILC cable that is determined to be in 'Very Poor' condition and is critical to the reliability of the system, will be replaced proactively. For example, Alectra Utilities has a multi-year project in 2029 and 2030 to replace deteriorated PILC cable between Beach Transformer Station (TS) and Ottawa Municipal Station (MS) in Hamilton. The renewal plan for PILC cable will be reviewed during this DSP period.

<u>A.6.2 EPR Cable</u>

EPR cables make up the smallest population of underground primary cables in Alectra Utilities' system, representing less than 1% of the total population. While costlier than XLPE, EPR insulation is recognized for its superior flexibility and smaller diameter than equivalent XLPE cable. As mentioned in the previous subsection on PILC, Alectra Utilities' practice is to use EPR cables as replacement option for reactive and planned PILC replacements. Due to the smaller diameter, three EPR cables can be bundled together and fit within existing 3.5-inch ducts. For EPR cables, long term degradation can occur due to mechanical damage, overheating, or the impact of moisture ingress and chemical deterioration.

Due to the small population of EPR cables, Alectra Utilities' current practice is to repair (e.g. splicing) or replace EPR cables reactively upon failure. Furthermore, the condition of existing EPR cable does not support a need for planned replacement over this DSP period. The utility will reassess the need for planned replacement for the next DSP period.

<u>A.6.3 XLPE Cable</u>

Alectra's distribution system has 23,106KM of primary underground XLPE cable, as detailed in *Chapter 5.3.2 (Section 5.3.2.2 A.1.6.3)*. XLPE cables are categorized by type, as described below. Each type has a different expected useful life, based on industry averages and Alectra's experience.

- **Non-Tree-Retardant cables (NON-TR)**:
  - Vintage 1988 or older; TUL 30 years; EUL 40 years
- **Tree-Retardant Direct-Buried cables (TR-DB)**:
  - Vintage 1989-1993; TUL 35 years; EUL 45 years
- **Tree-Retardant or Strand-Blocked In-Duct cables (TR-ID):**
  - Vintage 1994 or newer; TUL 40 years; EUL 55 years

Cable manufacturers introduced the first-generation XLPE cables in the late 1960s. These cables are susceptible to moisture ingress (i.e. water treeing) and localized failures, especially if installed direct-buried or with terminations and splices susceptible to insulation breakdown. The Non-Tree Retardant cables have inherent problems due to the technology and capability of the manufacturing processes available at the time, which led to the ingress of impurities into the insulating medium. These impurities can become triggers for the creation of water trees (i.e. small conductive paths in the insulation), which eventually become electrical trees. This issue causes insulation failures, resulting in faults on primary underground cables. The susceptibility of these cables to water and electrical treeing ultimately contributes to the partial discharge and eventual failure of the cable. As such, legacy XLPE cables introduce significant reliability concerns for Alectra Utilities. The breakdown of Alectra Utilities' cable population by cable type is detailed in Figure 5.3.2 – 57 in *Chapter 5.3.2 (Section 5.3.2.2 A.1.6).*

Compounding the issue is that these first-generation cables were originally installed in excavated trenches on a direct-buried basis, with little or no separation between cables, and without any additional mechanical protection that would be offered by a ducted installation. For this reason, these cables are difficult to replace or repair when they fail. Unlike failed cables installed in ducts, which typically can be entirely removed and replaced with brand new cable segments, failed direct-buried cables can only be excavated and repaired via cable splicing in a reactive situation. Such cable splices may introduce a potential failure point. Figure 5.3.3 - 12 and Figure 5.3.3 - 13 show examples of cable failure locations leading to disruptive outages experienced by customers. These complex outage locations may require specialized equipment, additional labour, and coordination with property owners to excavate and access the faulted cable. For customers, this means extended disruptions, inconsistent access to reliable power, and invasive repairs. As these failures become more frequent, customers will face increasing frustration over Alectra Utilities' ability to manage deteriorating cable in their neighbourhood.

Figure 5.3.3 - 12 Cable Under Backyard Deck

Figure 5.3.3 - 13 Cable Under Driveway

Manufacturing improvements and development of tree-retardant XLPE cables in the late 1980s have reduced the rate of insulation deterioration due to treeing effects. However, while tree-retardant cables are expected to last longer than their first-generation counterpart, the installation standards used at the time had yet to improve, as these cables were also direct buried and therefore similarly exposed to environmental factors. Further improvements in cable manufacturing in the early 1990s led to the development of strand-blocked XLPE cables, which are no longer susceptible to moisture ingress into the conductor. In addition, Alectra Utilities began installing primary underground cables in ducts in the early 1990s. As such, the life of the tree-retardant or strand-blocked in-duct cable is expected to be longer than the tree-retardant direct-buried cables.

Alectra Utilities' asset management strategy for XLPE cable follows a proactive approach and includes cable injection and cable replacement. Where feasible, Alectra Utilities performs cable injection as a lower cost solution that provides life extension benefits to existing XLPE and TR-XLPE (non-strand-filled) cables without excavation and replacement work. However, by 2029, Alectra Utilities will have no remaining feasible candidates for cable injection due to the amount of deteriorated aging in non-strand-filled cable. Many of the cables installed in the early 1990s are "strand-filled" and therefore not eligible for injection. When these cables begin to deteriorate, replacement is the only feasible option.

Figure 5.3.3 - 14 illustrates Alectra Utilities' general approach for prioritizing deteriorated XLPE cable.

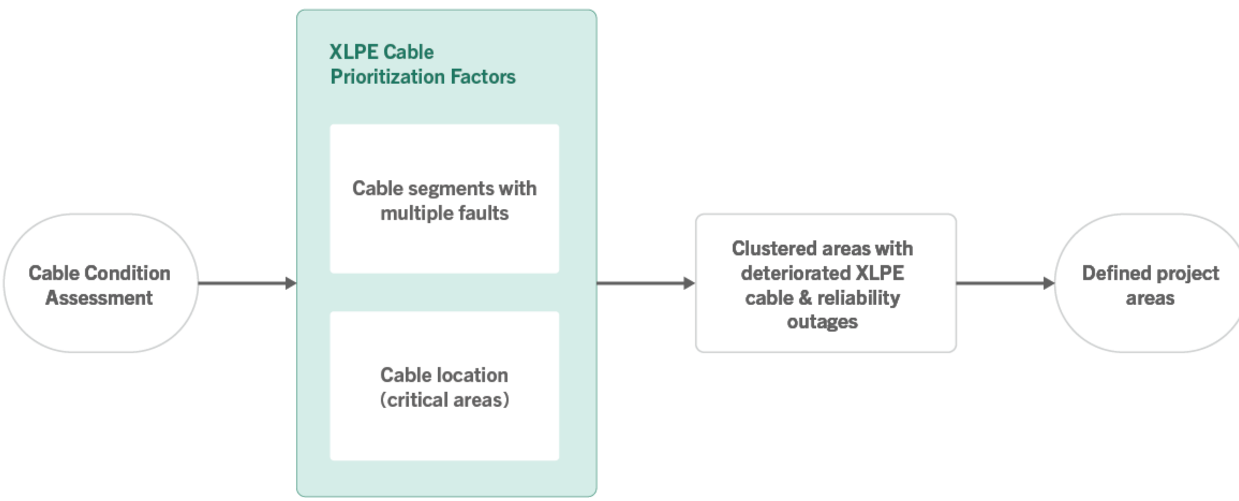

Figure 5.3.3 - 14 XLPE Cable Replacement Prioritization Steps

Alectra Utilities executes cable proactive remediation projects by geographical area to seek opportunities for efficiency savings (e.g. reduced logistical costs). In some cases, cable segments are targeted for remediation based on individual performance or consequence of failure. Cable accessories that are also of first-generation construction would be replaced along with the cable. As illustrated in Figure 5.3.3 - 14, defined project areas consider the following:

- <u>Health Index:</u> "Poor" and "Very Poor" cable segments (summarized in *Chapter 5.3.2 (Section 5.3.2.2 A.1.6.3))* according to the Cable ACA and adjacent cable segments
- <u>Cable Faults:</u> Cable segments with multiple faults that are susceptible to failure

- Reliability: Areas experiencing declining reliability due to XLPE cable faults
- Location: Deteriorated cable feeding critical infrastructure or located in an area where a cable failure will lead to a prolonged outage

Detailed discussion regarding options analysis and pacing of the cable replacement investment are provided in *Appendix B02 - Underground Asset Renewal (Section 2.4)*.

A.7 Other Distribution Assets

Alectra Utilities also proactively replaces the following distribution assets to avoid safety and reliability risks:

- Cable Chambers
- Fault Indicators
- Insulators
- Low Voltage Cables (Overhead and Underground)
- Submersible Load Break Device (LBD) Switches

These asset classes are not included in the ACA and are identified for remediation during inspection and maintenance activities (detailed in *Section 5.3.3.2*) in conjunction with reliability trends.

A.7.1 Cable Chambers

Utility chambers are below-grade concrete structures designed to facilitate the installation of underground cables and associated electrical distribution devices. These chambers can be located under roadways, parking lots, and boulevards, where they are frequently exposed to vehicle loading. It is imperative that they are maintained in sound condition, suitable for their continued application. Road salts, water run-off, and impact of vehicle loading can cause degradation of the concrete structure, thus jeopardizing the integrity of the chamber. Figure 5.3.3 - 15 illustrates a roof collapse of a cable chamber in downtown Hamilton. The entry neck section (chimney), upper roof slabs, and a small section of the load bearing walls are the areas that are most commonly impacted by this deterioration. Through regular inspections, Alectra Utilities identifies and evaluates signs of chamber structural deterioration.

The renewal of cable chambers includes full replacement (i.e. rebuild) and refurbishment concerning only the chamber opening or roof. Where feasible, the upper deck of the chamber is refurbished while leaving the remaining portion of the chamber intact. Where the chamber neck uses layers of brick to adjust the manhole to final grade, these bricks can deteriorate and may require either parging of the brick, or replacement of the chamber neck with a preformed concrete neck. The renewal plan, including ACA, for cable chambers will be reviewed during this DSP period.

Figure 5.3.3 - 15 Hamilton – Cable Chamber Roof Collapse

<u>A.7.2 Fault Indicators</u>

Fault indicators are a crucial component of the distribution system in terms of locating faults, thereby improving outage response and reducing outage restoration times. They support the sustainment of reliable system performance and customer service, as well as the attainment of operational efficiency gains. Alectra Utilities' distribution system includes various types of fault indicators, which were installed by Alectra Utilities' predecessor utilities pursuant to different practices in effect at the time. Some geographical areas of Alectra Utilities' service territory have a large number of fault indicators, while others have a smaller population or no-fault indicators at all. Alectra Utilities plans to:

i. Install new fault indicators in parts of the distribution system where fault indication is lacking

ii. replace older fault indicators that are technologically obsolete and prone to malfunction

A.7.3 Insulators

Alectra Utilities' overhead distribution system contains many insulators, including a population of legacy porcelain insulators and first-generation polymeric insulators[84]. The design of these insulator types has led to safety issues for Alectra Utilities' crews and reliability issues for the overhead distribution system. The identified insulators have displayed a susceptibility to the accumulation of contaminants to the degree where their insulating properties are reduced, resulting in tracking leading to flashover events. Flashovers have resulted in pole fires taking place and have caused reliability and safety risks to field crews and Alectra Utilities' customers. Figure 5.3.3 - 16 and Figure 5.3.3 - 17 show the loss of pole structure and pole failures caused by tracking insulators and resulting pole fires. Insulator replacements are targeted at replacing legacy porcelain and first-generation polymer insulators from the distribution system. Alectra Utilities has planned to continue replacing these assets to avoid insulator failure and the risks related to pole fires associated with these insulator types.

[84] Referred to as "non-K-Line" insulators

Figure 5.3.3 - 16 Pole Fire Due to Insulator Tracking

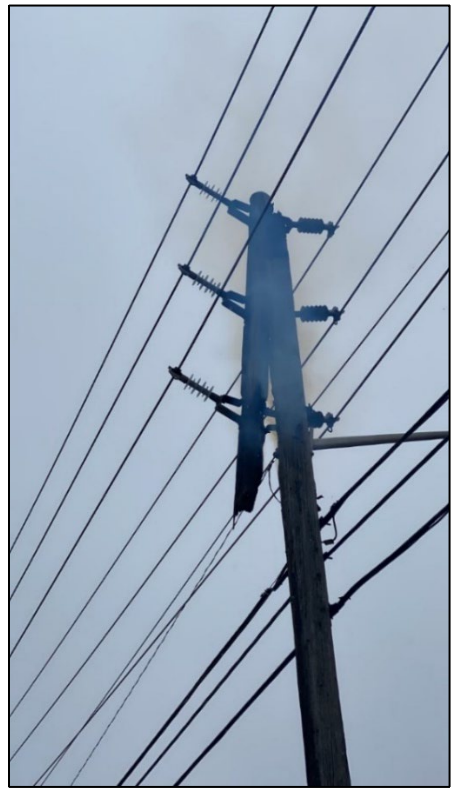

Figure 5.3.3 - 17 Active Pole Fire Event, 2023

Detailed discussions regarding options analysis and pacing of the insulator replacement investment are provided in *Appendix B01 - Overhead Asset Renewal*.

<u>A.7.4 Low Voltage Secondary Cable (Overhead and Underground)</u>

Alectra Utilities bundles the replacement of overhead main line secondary or service lateral conductors, or underground secondary and service cables as part of rebuild projects. Upon failure, these cables and conductors are replaced or repaired reactively.

<u>A.7.5 Submersible Load Break Devices (LBD)</u>

Alectra Utilities primarily manages its submersible LBD switches through reactive replacement. However, units that are vulnerable to flooding, no longer functioning as intended, or are obsolete (e.g. VACpac units) will be targeted for planned replacement. Figure 5.3.3 - 18 below shows a submersible switchgear corroded from repeated vault floods leading to unsafe operating conditions.

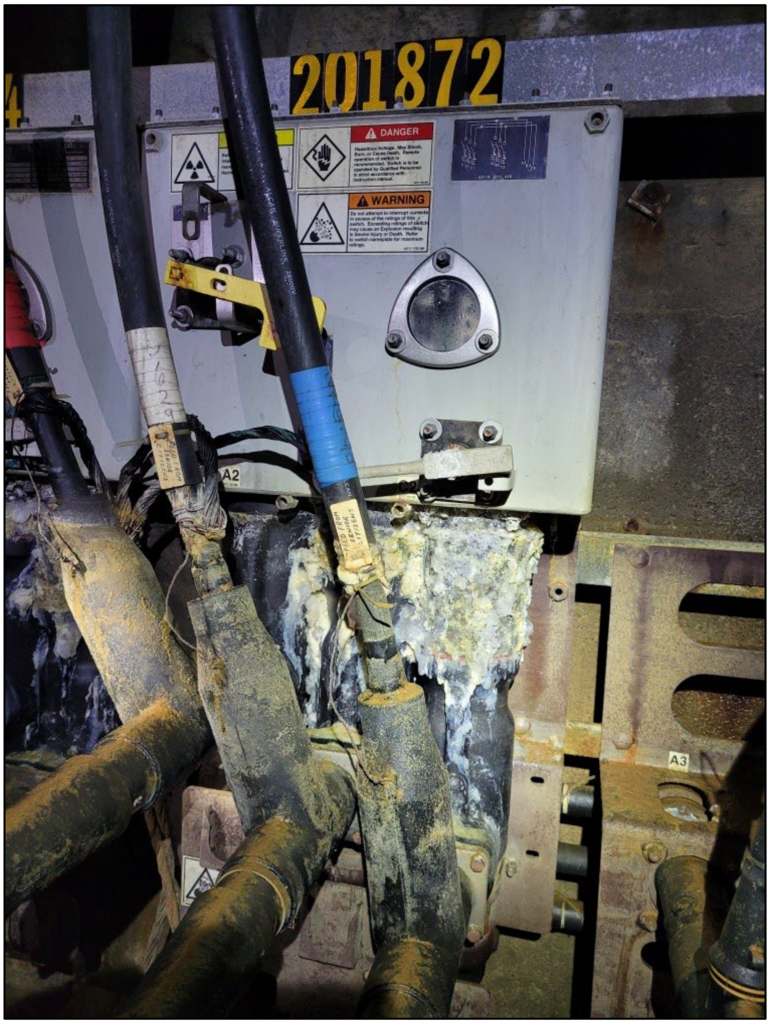

Figure 5.3.3 - 18 Corroded Submersible LBD Due to Flooding

B Station Assets

Alectra Utilities' station infrastructure is critical to the transformation of high-voltage supply from the bulk transmission system to distribution voltage supply. Station asset failure can lead to lengthy interruptions to many customers. Alectra Utilities owns and operates 14 Transformer Stations (TSs) and 149 Municipal Stations (MSs). These TSs are supplied from the Hydro One Network Inc.'s (HONI) high-voltage transmission grid at 115kV or 230kV, while the MSs are supplied from the low side of HONI's or Alectra Utilities' TSs at 44kV, 27.6kV, or 13.8kV.

The ACA assesses the following three major station asset classes:

- Power transformers
- Circuit breakers
- Station switchgear

Alectra Utilities' assessment of station assets also covers primary switches, station protection relays, station service transformers, and other ancillary equipment. Such assessments rely on the findings from stations' inspection and maintenance activities.

B.1 Power Transformers

Station power transformers are used to step down transmission or sub-transmission voltage to distribution voltage levels. The two general classifications of station power transformers are TS transformers and MS transformers. TS transformers are supplied from the high-voltage transmission grid at either 230kV or 115kV and step voltage down to 44kV, 27.6kV, or 13.8kV. MS transformers are supplied from the medium-voltage distribution system at 44kV, 27.6kV, or 13.8kV, and step voltage down to 27.6kV, 13.8kV, 8.32kV, or 4.16kV. TS transformers owned and operated by Alectra have fully cooled ratings of 50MVA, 83.3MVA, and 125MVA, and MS transformer ratings typically have base Oil Natural Air Natural (ONAN) ratings ranging from 3MVA to 22MVA.

Power transformers employ many different design configurations, but they are typically made up of the following main components: Primary and secondary windings, laminated iron core, internal insulating mediums, main tank, bushings, cooling system (including radiators, fans and pumps, where applicable), off-load tap changer (optional), on-load tap changer (optional), instrument transformers, control mechanism cabinets, and Instruments and gauges.

For most transformers, end of life is typically established as the failure of the insulation system and, more specifically, the failure of pressboard and paper insulation. While the insulating oil can be treated or changed, it is not practical to change the paper and pressboard insulation. The condition and degradation of the insulating oil, however, plays a significant role in aging and deterioration of a transformer, as it directly influences the speed of degradation of the paper insulation. Dissolved Gas Analysis (DGA) of the transformer oil and other test procedures provide important insights into transformer condition. Most of Alectra Utilities power transformers have some form of remote monitoring, with the most sophisticated systems being associated with the TS transformers. Through these systems, alerts can be transmitted to the control room when certain condition factors reach a pre-determined threshold, thereby triggering mitigation. In addition to remote monitoring, samples are extracted from each transformer at least once a year and sent to a laboratory for analysis. The results of this analysis will determine whether intervention is required. Intervention can include, but is not limited to, performing addition testing and even removing, degasifying, and replacing the oil.

Power transformer ACA results are summarized in *Chapter 5.3.2 (Section 5.3.2.2 A.2.1).*

Alectra Utilities has no plans for proactively replacing any power transformers during the 2027 to 2031 DSP period but will continue to manage aging units through online monitoring and enhanced inspection and maintenance practices, as deemed necessary. Alectra Utilities does expect that proactive power transformer replacements will be necessary soon after the 2027 to 2031 DSP period.

B.2 Circuit Breakers

Circuit breakers are used to sectionalize and isolate circuits or other assets. They are often categorized by the insulation medium used in the circuit breaker and by the fault-current interruption process. The common types include oil circuit breakers, air circuit breakers, vacuum circuit breakers, and SF_6 circuit breakers. Circuit breakers can be enclosed in switchgear or can stand alone.

Circuit breakers “make” and “break” high currents and experience erosion caused by the arcing accompanying these operations. All circuit breakers undergo some contact degradation every time they open to interrupt an arc. Also, arcing produces heat and decomposition products that degrade surrounding insulation materials, nozzles, and interrupter chambers. The mechanical energy needed for the high contact velocities of these assets adds mechanical deterioration to their degradation processes.

Outdoor circuit breakers may experience adverse environmental conditions that influence their rate and severity of degradation. Additional degradation factors for outdoor-mounted circuit breakers include corrosion, effects of moisture, bushing, insulator, and mechanical deterioration.

Corrosion and moisture commonly cause degradation of internal insulation, circuit breaker performance mechanisms, and major components such as bushings, structural components, and oil seals. Another widespread problem involves corrosion of operating mechanism linkages that result in eventual link seizures. Corrosion also causes damage to metal flanges, bushing hardware, and support insulators.

Outdoor circuit breakers experience moisture ingress through defective seals, gaskets, and pressure relief and venting devices. Moisture in the interrupter tank can lead to general degradation of internal components.

Mechanical degradation presents greater end-of-life concerns than electrical degradation. Operating mechanisms, bearings, linkages, and drive rods represent components that experience most mechanical degradation problems. Other effects that arise with aging include loose primary and grounding connections, oil contamination and/or leakage (oil circuit breakers only), and deterioration of concrete foundation affecting circuit breaker stability.

Failure of a circuit breaker to operate can lead to explosion, presenting a serious safety risk and a lengthy and costly service interruption.

Chapter 5.3.2 (*Figure 5.3.2 - 76)* illustrates that 114 circuit breakers are in the “Very Poor” or “Poor” condition category; all these circuit breakers are enclosed in station switchgear. Typically, circuit breaker replacement for units that are enclosed in station switchgear will trigger replacement of the entire switchgear lineup, including associated protections and ancillary equipment. Replacing the entire switchgear lineup rather than retrofitting the switchgear with new circuit breakers brings this station equipment up to current operating and safety standards. Alectra Utilities will be replacing some of these circuit breakers during the 2027 to 2031 DSP period as part of station switchgear replacements. Criteria for selecting replacement candidates are described in *Section 5.3.3.2 B.3.*

B.3 Station Switchgear

Station switchgear consists of an assembly of retractable/racked devices that are totally enclosed in a metal envelope (metal-enclosed). These devices operate in the medium-voltage range, from 4.16kV to 44kV. Station switchgear includes circuit breakers, disconnect switches or fuse gear, current transformers (CTs), potential transformers (PTs), and occasionally some or all the following: Metering, protective relays, internal DC and AC power, battery charger(s), and AC station service transformation. Station switchgear is modular in that each circuit breaker is enclosed in its own metal envelope (cell). Station switchgear is also compartmentalized, having separate compartments for circuit breakers, control, incoming/outgoing cables or bus duct, and busbars associated with each cell.

Switchgear degradation is a function of several factors: Mechanism operation and performance, degradation of solid insulation, general degradation/corrosion, environmental factors, and post fault maintenance (condition of contacts and arc control devices). Degradation of the circuit breaker used is also a factor. However, the degradation mechanism differs slightly between air-insulated and gas-insulated switchgear types. Note that circuit breakers are evaluated separately from station switchgear from an HI perspective.

The greatest cause of maloperation of station switchgear is related to mechanism malfunction. Deterioration due to corrosion or to lubrication failure may compromise mechanical performance by either preventing or slowing down the operation of the circuit breaker. This is a serious issue for all types of station switchgear.

In older air-filled equipment, degradation of active solid insulation, such as drive links, has been a significant problem for some types of station switchgear. Some of the materials used in this equipment, particularly those manufactured using cellulose-based materials (pressboard, SRBP, laminated wood), are susceptible to moisture absorption. This results in a degradation of their dielectric properties, resulting in thermal runaway or dielectric breakdown. An increasingly significant area of solid-insulation degradation relates to the use of more modern polymeric insulation. Polymeric materials, which are now widely used in station switchgear, are very susceptible to discharge damage. These electrical stresses must be controlled to prevent any discharge activity in the vicinity of polymeric material. Failures of relatively new station switchgear due to discharge damage and breakdown of polymeric insulation have been relatively common over the past couple of decades.

Temperature, humidity, and air pollution are also significant degradation factors. The safe and efficient operation of station switchgear and its longevity may all be significantly compromised if the station environment is not adequately controlled.

Older switchgear is not arc resistant. In the event of an explosive failure, the cabinet door could be blown off, resulting in a significant safety risk and extensive damage. Modern arc-resistant switchgear is designed with reinforced compartments that can withstand the pressure increases during high-energy faults, and explosive gases are vented, thereby significantly reducing safety risk.

Station switchgear ACA results are summarized in *Chapter 5.3.2 (Section 5.3.2.2 A.1.2.3*). Alectra Utilities will continue replacing station switchgear during the 2027 to 2031 DSP period. Station switchgear replacement will be arc-resistant and involves replacing the circuit breakers, associated protections, and ancillary equipment. Criteria for selecting replacement candidates are described in *Section 5.3.3.2 B.3*.

B.4 Protection and Control Systems

Protection and control system equipment consists of relays, remote terminal units (RTUs), communication switches, controllers, and computing platforms typically installed in a series of panels or in the low-voltage compartments of switchgear cells. Protection and control components can also be found in control cabinets of outdoor switchgear and transformers.

The primary function of a protection and control system is to provide monitoring and protection of station equipment and to initiate circuit breaker trip and close functions. This function is extremely important because it protects equipment from being damaged by high electrical currents that flow through electrical equipment during fault conditions. Protection systems operate to clear the fault by opening circuit breakers or other protective devices to cease the flow of fault current before equipment sustains damage.

Older station protection and control systems consist of protective relays that have an electromechanical mechanism or discrete solid state components. Such relays require periodic recalibration and have a limited range of functionality compared to modern protection and control systems. Degradation of electromechanical relays is primarily related to wear and seizing of mechanical mechanisms. Degradation of solid state relays is related to the deterioration of contacts and aging of electronic components. Degradation of either type can be due to the following factors: Contact oxidation, contact welding or pitting due to excessive current, and Chemical corrosion. Degradation on relay coils is mainly a result of thermal aging due to continuous energization or elevated cabinet temperatures. Excessive heat may cause the coil to burn out or affect other nearby components.

Modern protection and control components are predominately microprocessor-based digital devices that do not have mechanical or moving parts. They do not require periodic re-calibration and are also less likely to experience failure. Instead, other methods are used to confirm the health of the relay components; continuous monitoring through SCADA will reveal components that are not operating, and sequence of events reports provide confirmation that the protections are functioning properly. When compared to electromechanical or solid-state relays, microprocessor-based relays provide increased functionality and flexibility in terms of protection co-ordination and monitoring and control capability. Microprocessor-based relays require firmware updates to address security vulnerabilities, improve performance, and enhance compatibility with new software and hardware. Early generation microprocessor-based relays might not have all the functionality of modern relays and might be incompatible with new software and hardware. Also, there can come a point when it is no longer possible to update microprocessor-based relays, either because they operate on obsolete computer platforms, such as Windows 3.1, or firmware upgrades are no longer available. For any relay type, the availability of parts may become limited once no longer supported by the manufacturer. Should these legacy relays fail, customer outages could result, and it may be not easy to repair or replace the asset.

Replacing end-of-life electromechanical, solid state, and earlier generation microprocessor-based protection equipment with modern microprocessor-based systems results in improved protection co-ordination between station circuit breakers and downstream protective devices such as reclosers and fuses. This provides better protection for system assets but also results in better reliability because outages can be contained more effectively to the problem area. In addition, improved protection co-ordination results in fewer momentary outages, which are a nuisance to customers with sensitive electronic equipment and can disrupt entire industrial customer production processes. Modern microprocessor-based systems also enable better protection of station and distribution assets and support initiatives to enhance substation automation by implementing functionality such as automatic transfer capability, thereby reducing the possibility of customer outages during fault or equipment failure situations.

Protection and control system upgrades are prioritized based on asset criticality, remaining useful life, required functionality, and alignment with other projects. Where the primary driver for replacement is condition, investments are covered under Substation Renewal. Assets in deteriorating condition are identified by a history of failure or by increased maintenance or repair requirements; these investments are discussed in *Appendix B04 - Substation Renewal*. Where the primary driver for replacement is a need for additional functionality or to support other systems, investments are discussed in *Appendix B14 - Enabling Resiliency & Modernization (Section 2.1.4 C*).

B.5 Station Renewal Strategy

In addition to HI scores, Alectra Utilities' strategy for managing station assets involves the use of monitoring technologies, investing in environmental protection measures, and strategically managing inventory on a consolidated basis (refer to *Chapter 5.4.2 2027-2031 Investment Overview* for further details). When considering station renewal activities, the following factors are evaluated to assess and mitigate the risk profile at any given station:

- Station configuration: Alectra Utilities' stations utilize both single and dual-element (transformer) arrangements. The dual-element configuration includes two transformers per station such that each transformer can normally support the full station load. Alectra Utilities monitors the HI value of each transformer to assess the overall transformer risk at the station and determines the timing for replacement of either of the transformers.
- Inter-station connectivity and back up: All of Alectra Utilities' stations are interconnected through overhead and underground feeder systems, such that load can be effectively transferred in most conditions upon the loss of all or part of a station.
- Spare asset inventory: Alectra Utilities ensures that sufficient spare power transformers and circuit breakers and/or spare parts are available by rating and operating voltage levels to support the station fleet. Spare transformers and circuit breakers may be located within a station site or in stores inventory. In some cases, spare units may be moved to station sites with higher risk profiles.
- Station peak loading: Alectra Utilities monitors station loading on a continuous basis, capturing hourly peak load values throughout the year. If certain

transformers exhibit high risk profiles, loading information will be used to assess offloading capabilities and the need for station asset replacements.

- Station capacity upgrade projects: Through the integrated planning process, Alectra Utilities will identify the timing and location of station sites where capacity upgrades are required. The Asset Management team, in consultation with Station Sustainment, will assess the risk profile of the station transformers involved and determine if the existing transformers can be maintained until the scheduled upgrade is executed. Depending on the timing of the capacity upgrade and the risk profile of the existing transformers, consideration will be given to offloading, oil de-gassing and potential refurbishment activities. If transformers that have been replaced are in Fair or Good condition, they may be tested and refurbished and maintained as spare units.
- Station decommissioning schedules: Some of Alectra Utilities' lower-voltage distribution systems are undergoing conversion to current-day standard operating voltages, through the completion of multi-year voltage conversion projects. The station risk profile for municipal stations identified for conversion are assessed with regard for the scheduled decommissioning (if applicable) of the station. Where a station with a higher risk profile is within the scope of a planned conversion project and is scheduled to be decommissioned in the short term, the risks associated with that station may be addressed by increased maintenance or refurbishments to maintain reliable operation until the decommissioning date. For Alectra Utilities voltage conversion plan in this DSP, refer to *Appendix B01 - Overhead Asset Renewal*.

As a key input for the station asset management process, HI results for major station assets are compiled for each station and provided to SMEs for review and analysis. SMEs consider HI results along with other input, including station maintenance history, station component performance issues, and station component replacement initiatives not managed through the ACA process (such as capital corrective replacements, including transformer tank and radiator reconditioning, transformer leak mitigation/re-gasketing, and procurement of critical spare parts).

Alectra Utilities considers the condition of all major assets located within a given station and completes a thorough evaluation in consultation with SMEs across relevant departments to identify assets that warrant follow-up action plans as well as opportunities to bundle work by station. Other than the previously mentioned input factors, SMEs also consider station decommissioning schedules associated with voltage conversion projects, expansion requirements, capacity constraints, magnitude and criticality of the load that is supplied, type of customers supplied, potential stranded load conditions, distribution system load transfer capabilities, obsolescence, availability of parts, maintainability, safety and environmental concerns and budgetary constraints. Based on this evaluation, project business cases are prepared for the identified assets, integrating all applicable cross-functional drivers as part of Alectra Utilities' integrated planning process.

C Metering Assets

As of December 31, 2024, Alectra Utilities' metering asset portfolio consists of 498 wholesale revenue meters and 1,082,436 retail revenue meters. As detailed in *Appendix B06 - Network Metering*, the condition, performance, and accuracy of metering assets is mandated by federal statutes (the *Weights and Measures Act and the Electricity and Gas Inspection Act)*, by Ontario Energy Board code requirements, and under the IESO's *Market Rules*.

Wholesale revenue meters are critical for ensuring the accurate and reliable measurement of electricity delivered to the utility through the provincial grid and distributed by the utility to customers. They are installed at bulk supply points, transformer stations, and municipal substations.

Retail meters include single-phase, polyphase, and suite meters installed at customer premises across residential, commercial, and multi-unit buildings. Approximately 90% of the retail meters are networked, and the broader metering system includes communication networks equipment and software platforms or "Head Ends" that together enable the accurate, secure, and timely provision of meter data.

C.1 Wholesale Revenue Metering

As described *Appendix B06 - Network Metering* (*Section 3.1.1)* Wholesale Revenue Meter Compliance, Alectra Utilities typically schedules the replacement of its wholesale revenue meters prior to the assets reaching 20-25 years in service. This is typically the end of their practical life where the meter model or firmware is no longer supported by the manufacturer, or it becomes impractical to meet Measurement Canada's re-sealing requirements. The meter may be replaced earlier in cases of in-service failure or due to measurement inaccuracies.

Alectra Utilities wholesale revenue meter fleets have an average age of 9.3 years, with 51 meters aged 15 to 17 years, and 59 meters aged 18 to 20 years as of December 31, 2024. Alectra Utilities' wholesale revenue meters are part of the broader wholesale metering installation which also includes cabinets, cabling, and instrument transformers.

Alectra Utilities follows a replacement plan based on a useful life of approximately 40 years for its wholesale instrumentation. This is aligned with historical failure trending for the assets. Additional proactive replacements are incorporated into the plan as regulatory changes require compliance upgrades, or when station rebuilds or switchgear replacements are completed. Instrumentation replacements may be required reactively where measurement inaccuracies are identified or when a total failure occurs.

C.2 Retail Revenue Metering

As described in *Appendix B06 – Network Metering (3.1.4 Meter Failures),* most meter models are relatively stable with failure rates aligned to the industry standard of up to 0.5% annually. Under this normal life-cycle scenario, Alectra Utilities reactively replaces both networked and non-networked meter assets as they fail.

As its networked Advanced Metering Infrastructure (AMI) 1.0 meters age, Alectra Utilities is experiencing increased meter failure rates, approximately double the industry standard (i.e. 1.1%) in 2024.

Managing a large-scale meter network using a reactive or "run-to-fail" model is neither a practical nor reliable approach at Alectra Utilities' current rate of failure for its AMI 1.0 meter assets. Each failed meter can disrupt the mesh network it supports, reducing the overall system resilience. A high volume of meter failures may destabilize the network entirely, leading to cascading communication failures that prevent data from reaching the AMI head-end system. Failure rates incrementing beyond 1% are not cost effective nor operationally practical to be managed reactively, and a planned AMI renewal strategy is required.

Alectra Utilities' planned replacement strategy for its AMI 1.0 network meters is provided in *Appendix B06 - Network Metering (Section 3.1.5)*.

5.3.3.4 Asset Refurbishment Practices

Asset refurbishment is a structured intervention aimed at restoring and rebuilding assets removed from the field due to failure or through planned replacement projects. It is intended to target assets that can be returned to an acceptable functional state, pass required testing and be reintroduced to the system. Refurbishment differs from maintenance in that maintenance involves on-site repairs or localized replacement of asset components, whereas refurbishment is typically performed after the asset has been removed from service and entails a more extensive off-site rebuild. The two exceptions to refurbishment with in-situ interventions to extend the life of the asset are cable chamber refurbishment (e.g. repairing chamber opening or roof) and underground cable injections. Alectra Utilities considers these as refurbishment due to extensive impact on the asset functional integrity and useful life.

The two main scenarios for asset refurbishment exist.

a) **Assets replaced in the field that are still functional**

These are major electrical assets that are proactively removed from service due to temporary installations, service upgrades, infrastructure modifications, aging and risk of failure. These assets have not encountered any failures and may still be operational at the time of removal. They undergo adequate testing to ensure they are fit to be added back into inventory. An example can be a pole mounted transformer that was returned after being installed for temporary installation for a customer until the permanent service was established. This asset has considerable useful life remaining and upon passing all the required testing, it can be used for future installations especially on a reactive basis.

b) **Assets that have failed in the field**

This scenario applies to assets that have sustained a failure while in service but, upon inspection, are determined to be repairable and suitable for refurbishment after removal from the field. In these cases, refurbishment may be pursued as a cost-effective solution, provided the damage is localized and the core structure or components of the asset remain intact. When applicable, these assets may undergo warranty repair processes through the Original Equipment Manufacturer (OEM) or designated service providers. The refurbishment process typically includes a root cause analysis to identify and mitigate the underlying cause of failure, which may inform future asset strategies. Following repairs, the asset is subject to functional testing, quality assurance and re-certification before it is deemed suitable for adding back into inventory. This approach allows the utility to recover value from failed assets while ensuring performance standards are met and reliability risks are mitigated.

The refurbishment criteria are based on a set of engineering, economic, and operational factors that include the following:

- Remaining Useful Life
- Cost Comparison: Refurbishment vs. Replacement
- Expected Life Extension
- Obsolescence and Part Availability
- Impact on Reliability and Operations
- Warranty and Post-Refurbishment Assurance

The major electrical assets that are considered for refurbishment include switchgear, pole-mounted switches, reclosers and transformers. For pad-mounted switchgear units, commonly used in residential and commercial areas, annual inspections or operational observations may reveal localized component defects, such as cracked support insulators, damaged fuse holders, or corona-damaged barrier boards. Where feasible, targeted repairs are performed off-site to restore functionality and extend service life. Pole-mounted switches and reclosers are also assessed through inspections and operational observations. Key points include pitted contacts, faulty arc suppressors, binding linkages, communication issues with the relay, or missing weatherproofing components, all of which can be economically repaired to avoid full asset replacement. Transformers are typically removed as part of planned upgrades or voltage conversions unless they have failed in the field. Once removed, they are evaluated for refurbishment based on manufacturer specifications and industry standards. Key components assessed include the condition of the core and windings, oil insulation, bushings, and gasket integrity. Where results support viability, reconditioning and component replacement are pursued to restore operational reliability. Refurbished units are then returned to inventory, mainly for reactive use, offering significant cost savings and avoiding lengthy lead times over procuring new units while ensuring support for legacy system configurations.

Refurbishment also plays a key role in underground cable chambers and distribution substations. Utility chambers are subsurface concrete enclosures that house cable infrastructure and are exposed to vehicle loading, water intrusion, and de-icing salts. These issues can lead to deterioration, particularly of roof slabs and upper wall sections. Where inspections reveal structural degradation, the chambers are refurbished in situ by restoring the upper deck while retaining the lower section, thereby preserving structural integrity and deferring costly replacements. In substations undergoing phased renewal or decommissioning, salvageable equipment such as power transformers and circuit breakers is evaluated for refurbishment potential. Condition testing determines whether components can be recertified for reuse, particularly in support of vintage systems. In cases where OEM support has ended, refurbished components are returned to inventory as legacy spares, supporting operational continuity and minimizing disruption during the transition away from obsolete systems.

5.3.3.5 Impact of Asset Replacements on Maintenance

Alectra Utilities' asset renewal programs are designed to replace functionally obsolete, deteriorated, and end-of-life assets. Alectra Utilities anticipates asset renewal programs targeting certain legacy distribution system assets will contribute to a gradual and modest reduction in required maintenance for select asset types, where legacy assets are retired and replaced with newer, standard equipment. Newer equipment typically requires less maintenance since deterioration has not yet affected the functionality of the asset. The legacy assets include but are not limited to the following:

- Porcelain insulators: replacing these units with standard polymer insulators eliminates the requirement for insulator washing
- Air-insulated pad-mounted switchgear: replacing these units with current standard solid-dielectric switchgear eliminates the requirement for dry ice cleaning
- Overhead switches: replacing these units with sealed automated switches eliminates the need to perform routine maintenance on the legacy switches

At the same time, planned system expansion will introduce new assets to the system, resulting in corresponding increases to O&M costs. Further, the following planned maintenance activities remain generally independent of system renewal expenditures:

- Maintenance activities following disruptions and damages caused by emergencies or major weather events

- Scheduled inspections that must comply with the OEB's minimum inspection requirements
- Corrective maintenance activities to address issues stemming from ongoing asset deterioration and external factors (e.g. exposure to environmental elements, animals, insects, vegetation)
- Vegetation management to ensure that clearance requirements for overhead assets are met

As part of the evaluation of the financial benefits and costs associated with system renewal investments, Alectra Utilities determines and assesses, where applicable, each candidate project's impact on OM&A expenditures, whether representing cost savings or additional cost pressures. As detailed in *Chapter 5.4.1 Capital Expenditure Summary*, this assessment forms part of the standard financial evaluation performed through the Copperleaf Portfolio system.

5.3.3.6 Asset Renewal Quantities & Prioritization

Assessing risk is an integral part of the Alectra Utilities' asset lifecycle optimization process. For each project in Copperleaf Portfolio, the risks avoided and benefits realized upon project completion are assessed. Alectra Utilities' asset lifecycle risk management practices incorporate information obtained from multiple asset management-related processes are detailed in *Chapter 5.3.1 Asset Management Process Overview.*

Alectra Utilities utilized Copperleaf's Predictive Analytics (PA) tool in conjunction with the Copperleaf's Value Framework methodology as outlined in *Chapter 5.3.1 Asset Management Process Overview*, to support asset class lifecycle optimization – determining the quantity of distribution asset replacements for the following four renewal equipment categories:

- Transformers – Overhead, Pad-mount, and Vault
- Poles – Wood and Concrete
- Switches
- Switchgear

Copperleaf's PA model determines asset replacement schedules based on avoided risk and net economical value model. The mentioned model predicts the appropriate assets to replace that generates value for customers based on Value of Lost Load (VOLL). The output is then used to identify targeted assets that are allocated for replacements over the 2027 to 2031 period. The PA approach used to justify these renewals is consistent with the management practices and principles described in this chapter. This section outlines the details the steps undertaken in Copperleaf's PA and Value Framework to derive asset replacement quantities. The process is as follows:

1. **Establish conditional Probability of Failure (POF) for each asset class as a function of age and asset health.** The Copperleaf PA model is configured to predict asset failure rates based on their condition-adjusted age and associated probability of failure. The model integrates asset health indicators before computing the POF by modifying each assets' chronological age based on its testing and inspection results. The underlying POF and failure rate formula for each asset class remains consistent with the Gompertz-Makeham Model used in Alectra Utilities Asset Condition Assessment (refer to *Appendix E - Asset Condition Assessment* for details).
2. **Assess the net economical value of asset renewals.** The process compares the cost of renewal to the quantified monetary consequences of asset failure for the following value drivers. The cost is derived from Copperleaf's Value Framework and its consequential calculations for the four asset categories.
   - Employee Safety – exposure, severity, and cost of employee safety event
   - Public Safety – exposure, severity, and cost of public safety event
   - Environmental – cost of oil containment and clean up
   - Financial – cost of reactive replacements
   - Reliability – cost of equipment failure based on asset criticality, duration, and outage cost[85]
3. **Generate asset renewal projections for the next 40 years.** The PA model's outcomes and Copperleaf's Value Framework assessment from prior steps are used to generate the replacement quantities that are economically justified for replacement for the next 40 years.

[85] Outage cost varies due to duration, load at risk, and customer mix (residential, commercial, and industrial).

4. **Apply and assess pacing scenarios and select optimal asset replacement pacing option.** Alectra Utilities reviewed the output of the PA process and its recommended asset renewal projections. Based on engineering assessment of risk, customer benefit, ability to design and resources to execute the work; assets were placed into two groups. Group 1 includes switches and switchgear, while Group 2 includes poles and transformers. Three pacing scenarios of Reduced, Moderate, and Accelerated were defined and evaluated during portfolio optimization in Copperleaf, as well as to provide choices for customer engagement. *Section 5.3.3.3 A* details the asset replacement pacing quantities selected for each of the four asset investment categories.

As mentioned in Step 4 above, Alectra Utilities reviewed Copperleaf's PA replacement forecasts for two distribution asset groups. Group 1 includes switches and switchgear, and Group 2 includes poles and transformers. To establish a sustainable pacing strategy, the PA model's 40-year output projection were assessed alongside key considerations such as customer benefit, design and construction feasibility, resource availability, and supply chain constraints. As a result, Alectra Utilities defined the following three pacing scenarios to re-evaluate through Copperleaf's portfolio optimization, and offer alternatives to adjust based on customer feedback:

- <u>Pacing 1 - Accelerated:</u> front-loads replacement, assets forecasted in the first 20 years are replaced over a 15-year period, with the remaining 20 years replaced over a 25-year period
- <u>Pacing 2 - Moderate:</u> assets forecasted in the first 20 years are replaced over a 20-year period, with the remaining quantities replaced over the second 20-year period.
- <u>Pacing 3 - Reduced:</u> Extends the replacements of first 20 years evenly across 30 years, and the last 20 years are compressed into a 10-year period

The Copperleaf optimization ultimately selected one of the pacing strategies for inclusion in the budget for each of the asset groups.

Group 1 (Switch and Switchgear): The PA model's forecasted replacement quantities for switches and switchgear presented no significant pacing issues, hence they were grouped together. For Switchgear, Copperleaf's optimization process selected the Reduced pace.

However, to align with Distribution Automation Level Two (self-healing) plans, the replacement quantities of the last two years (2030-2031) were increased. This was to specifically support the increased automation investments which provide direct customer benefit by improving reliability. These pacing options were then presented to customers in the second round of customer engagement. Following customer engagement (*Exhibit 1, Tab 5, Schedule 2 Application-Specific Customer Engagement*), the pacing for switches was changed from Reduced to Moderate to align with customer feedback to increase overhead spending. For switchgear, Reduced pacing options remained with an increase in the last two years.

Group 2 (Poles and Transformers): The PA model's original forecast identified an immediate backlog of approximately 38,000 poles and 17,500 transformers that were deemed economically justified for replacement as early as 2025. While addressing these volumes are economically beneficial (i.e. lower total lifecycle cost of asset), they are not feasible to execute given the current supply-chain and resource constraints. Therefore, Alectra Utilities proposed to smooth the renewal volumes of the initial years to a manageable pace and prioritized the replacement of high-risk, most deteriorated poles and transformers in earlier years.

The adjusted replacement quantities were evaluated under the three different scenarios shown in Table 5.3.3 - 5 and Table 5.3.3 - 6. Copperleaf's optimization selected the Moderate pace for both poles and transformers, except for one region where poles remained at the Reduced pace. The selected option was presented to the customers during the second round of customer engagements. Based on the feedback from customer engagements, the Moderate pacing strategy was adopted across all regions for both asset classes.

Table 5.3.3 - 5 Pacing Option: Poles

Pacing Option: Poles	2027	2028	2029	2030	2031	Total
Reduced	746	746	985	1,105	1,250	4,832
Moderate (Selected Option)	826	925	1,025	1,180	1,300	5,256
Accelerated	960	1,100	1,250	1,400	1,555	6,265

Table 5.3.3 - 6 Pacing Option: Transformers

Pacing Option: Transformers	2027	2028	2029	2030	2031	Total
Reduced	590	700	844	979	1,109	4,222
Moderate (Selected Option)	680	844	964	1,082	1,201	4,771
Accelerated	844	964	1,083	1,203	1,348	5,442

Alectra Utilities use these analyses to support the development of technical alternatives in project business cases to avoid identified risks. As discussed in *Chapter 5.3.1 (Section 5.3.1.1 A.5)*, Copperleaf Portfolio uses the Value Framework to evaluate the value of an investment. The benefits and risk measures that include probability and impact are inputs to the Value Framework. The risk information is used to facilitate selection of a recommended alternative for investment portfolio optimization in Copperleaf Portfolio.

The overall approach of the DSP in terms of proposed plans is to either maintain or reduce the residual risk profile for high impact assets, such as poles, switches and switchgear, while considering various practical factors, such as supply chain and resource requirements. As is evident from the system renewal needs, the plan is crucial to reduce the safety, environmental, financial, and reliability risk.

5.3.4 System Capability Assessment for Renewable Energy Generation (REG)

Refer to *Appendix A* for Alectra Utilities’ system capability assessment for Renewable Energy Generation (REG).

5.3.5 Non-Wires Solutions to Address System Needs

5.3.5.1 Introduction

This chapter explains how Alectra Utilities considered Non-Wires Solutions (NWS) over the 2027-2031 period, describes the policy-aligned framework Alectra Utilities established to assess opportunities and summarizes the resulting station deferrals proposed for the DSP Period.

Alectra Utilities considered NWS when developing and prioritizing projects for this DSP. Where system needs, timing, and technical feasibility suggested a credible deferral, those needs were identified for further NWS assessment.

Following issuance of the OEB's *Non-Wires Solutions Guidelines for Electricity Distributors* in 2024[86], Alectra Utilities developed a NWS Screening Framework and applied it to the DSP investments. In most instances, Alectra Utilities expects that NWS will be a temporary solution to growth and capacity needs, not a permanent one. With the IESO system-level net annual energy demand forecast to grow by 75% by 2050[87], traditional capacity investments will remain essential to maintaining safe and reliable service.

As set out in *Appendix B13 – Stations Capacity*, Alectra Utilities has deferred five Stations Capacity investments that would otherwise have been included in this DSP, based on the application of the NWS screening Framework, using Distributed Energy Resources (DERs) and Demand Response (DR).

Alectra Utilities recognizes that the NWS market is still in the early stages of development, and additional work will be required to confirm the availability of uncommitted DER, to develop and refine locational DDR tariffs, and to validate resource reliability across operating conditions. Further, Alectra Utilities' ability to deploy these and future NWS is contingent on funding and technical implementation of enabling technologies proposed in this application, including Advanced Distribution Management System, Integrated Network Management, Planning Tools and Automation, and DER Wholesale Market Preparedness, as set out in *Appendix B14 - Enabling Resiliency and Modernization*. Despite the challenges, Alectra Utilities is committed to

[86] EB-2024-0118, *Non-Wires Solutions Guidelines for Electricity Distributors*, March 28, 2024.
[87] *Annual Planning Outlook*, Ontario's electricity system need 2026-2050, April 2025.

identifying and deploying NWS where they can cost-effectively and reliably address capacity challenges on the distribution system. The investments in this DSP reflect that commitment.

Recognizing the execution and market uncertainty around aspects of the necessary NWS expenditures, Alectra Utilities has not included the NWS OM&A costs in the revenue requirement forecast in this application. Instead, the company proposes to establish a Non-Wires Solutions Deferral Account (NWSDA) to record the actual costs of acquiring DERs, and operating and managing the NWS program, during the 2027-2031 period for subsequent OEB review and disposition (refer to *Exhibit 9, Tab 2, Schedule 1 Establishment of New Deferral and Variance Accounts*). Alectra Utilities believes this approach to NWS provides value to customers, through the deferral of otherwise necessary capacity investments, while allowing for a mechanism to recover the cost of procuring and operating necessary DERs, subject to OEB review.

Consistent with the OEB's active policy initiative EB-2025-0083 and Filing Guidelines for Incentives for Electricity Distributors to Use Third-Party DERs as Non-Wires Alternatives issued on March 28, 2023, Alectra Utilities proposes to apply a Margin on Payments (MoP) incentive to third-party DER procurements used as NWS during the DSP plan term. Alectra Utilities proposes a MoP of 25% of payments to third-party DER providers, aligned with the OEB's proposed amendments to the DSC, and subject to the eligibility criteria. The implementation and recovery of the MoP are set out the NWSDA proposal (refer to *Exhibit 9, Tab 8, Schedule 1 Establishment of New Deferral and Variance Accounts*).

The remainder of this section is structured as follows:

- *Section 5.3.5.2* – Historical Progress and Experience with NWS: Alectra Utilities' leadership in Ontario's initial NWS pilots and its early efforts to embed NWS in system planning
- *Section 5.3.5.3* – Current state of NWS Consideration: Summarizing Alectra Utilities' NWS Framework and adjustments to the planned capital program, and how they align with OEB guidance
- *Section 5.3.5.4* – Preliminary NWS Framework: A description of Alectra Utilities' screening methodology and evaluation criteria
- *Section 5.3.5.5* – NWS Framework Application in this DSP: Detailing Alectra Utilities' NWS screening results and the Margin on Payment proposal

5.3.5.2 Historical Progress and Experience with NWS

Although the OEB does not require Local Distribution Companies (LDC) filing in 2025 to comply with the new Benefit-Cost Analysis set in Benefit-Cost Analysis Framework for Addressing Electricity System Needs issued on May 16, 2024 (BCA Framework), Alectra Utilities has proactively begun integrating NWS considerations into its capital-planning decisions for this application.[88] Early actions include pilot projects, development of the company's NWS Framework, and initial application of screening criteria to system needs identified in the 2027-2031 period.

Alectra Utilities has also leveraged insights gained as the lead participant in the IESO York Region Non-Wires Alternatives Demonstration Project, Ontario's first NWS pilot. This initiative provided Alectra Utilities with early understanding of the technical, operational, and procurement requirements necessary to deploy demand response and DERs at a distribution level, and it has informed Alectra Utilities' evolving approach to NWS integration.

The pilot targeted growing capacity requirements in southern York Region, where substantial conventional reinforcements would be necessary (refer to *Appendix J - Load Forecast & System Capacity Adequacy Assessment Report*). Acting as the local distribution company and technical interface to the Independent Electricity System Operator (IESO), Alectra Utilities supported the project's architecture – comprising a local capacity auction, coordinated operational dispatch, and measurement-and-verification protocols. A full description of the project is provided in the IESO York Region Non-Wires Alternatives Demonstration Project Evaluation Report[89].

[88] The OEB's NWS requirements (in particular the BCA Framework) were finalized in May 2024, by which time when Alectra Utilities' DSP projects were well underway.
[89] https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/yrnwa/YRNWA-20240723-Final-Report.pdf

Key outcomes of the York Region pilot included:

- Successful procurement and dispatch of 10MW in Year 1 and 15MW in Year 2 of DER capacity (demand response and thermal resources) within the constrained area
- Design and execution of a DER capacity-auction mechanism, yielding valuable insights into price discovery, vendor readiness, and system-visibility needs
- Identification of integration and interoperability challenges – particularly communication protocols, telemetry requirements, and LDC-IESO operational coordination
- Enhanced understanding of DER technical capabilities and performance under real-world dispatch conditions
- Documentation of lessons learned, including success factors and barriers related to procurement lead times, customer engagement, and value-stack alignment

Participation in this pilot provided Alectra Utilities with direct, hands-on experience in the practical and regulatory dimensions of enabling NWS at the distribution level. It clarified the technical enablers, such as telemetry, communications, and system visibility, and operational processes with the governance mechanisms required to extend NWS deployment across the service territory.

5.3.5.3 Current State of NWS Consideration

Alectra Utilities has embedded several process enhancements in its 2027-2031 DSP planning processes to support deployment of NWS, where they can cost-effectively address system needs.

Alectra Utilities has integrated NWS considerations into the DSP through the measures outlined below. These actions lay the groundwork for full BCA Framework compliance beginning with the company's next DSP filing cycle.

- **Preliminary NWS Framework** – Alectra Utilities has adopted an internal screening methodology, aligned with OEB principles, to identify candidate projects for NWS. The framework is described in *Section 5.3.5.4*.
- **Incorporating BCA framework in Copperleaf system**- Alectra Utilities will enhance Copperleaf to incorporate BCA analysis for applicable investments.

- **Screening of Capacity-Driven Investments** – All Lines Capacity and Stations Capacity projects were reviewed to determine whether NWS could partially or fully satisfy the identified need.
- **Incorporation of Conservation and Demand Management (CDM) in Load Forecasting** – The load-forecast methodology embedded historical and forecast CDM impacts, ensuring capacity planning reflects net demand.
- **Alignment with Regional Planning Priorities** – Where Integrated Regional Resource Plans (IRRPs) highlight NWS potential, Alectra Utilities has coordinated project scopes and timelines with IESO recommendations (refer to *Chapter 5.2.2 Coordinated Planning with Third-Parties*).
- **Advancement of NWS-Enabling Technologies** – Recognizing that effective NWS deployment requires enhanced system intelligence and control, Alectra Utilities continues to invest in grid modernization tools that support DER integration (refer to *Appendix B14 - Enabling Resiliency & Modernization*).
- **Ongoing Engagement with IESO and Market Participants** – Alectra Utilities continues to collaborate on follow-on initiatives from the York Region pilot and participates in IESO working groups (e.g. DER Potential Study, Transmission-Distribution Coordination Working Group, DER Market Vision and Design Project) to refine procurement models, dispatch protocols, and performance validation.

5.3.5.4 Preliminary NWS Framework

This section sets out Alectra Utilities' screening framework for screening, evaluating and selecting NWS to meet system needs. Alectra Utilities refers to this process as its preliminary "NWS Framework".

A Design Principles and Precedents

Alectra Utilities has developed a NWS Framework and applied it to the DSP capacity related investment, following issuance of the OEB's *Non-Wires Solutions Guidelines for Electricity Distributors*. The NWS Framework is principles-based. It intends to identify system needs for which an NWS could represent a cost-effective, technically feasible alternative, and provide a consistent, transparent decision-making and early integration of NWS considerations in the capital-planning cycle, while remaining flexible as the process matures and market conditions and enabling systems evolve. The NWS Framework draws on Alectra Utilities' experience in the IESO York Region NWA pilot, coordination through Regional Planning Processes, and internal planning practices. *Section 5.3.5.4.D* describes the high-level gating used in the framework.

B Definition of Non-Wires Solutions

An NWS is any single measure or bundled portfolio of measures, other than traditional poles-and-wires investments, that reduces, shifts, or manages electrical demand at a specific constraint point, thereby allowing a conventional solution to be deferred, right-sized, or avoided.

C NWS Options

Alectra Utilities will develop the detailed catalogue of NWS option as part of the DER Supporting Technologies capital project as described in detail in *Appendix B09 – Information Technology Systems*, and in Planning Tools and Automation project as described in detail in *Appendix B14 – Enabling Resiliency and Modernization* and update it as market depth and enabling systems mature.

The following illustrative, non-exhaustive NWS categories outline the range of solutions that may be deployed, individually or combined, into NWS 'portfolios' for future application to specific needs:

- Targeted demand response (residential, commercial and industrial)
- Battery energy storage
- Solar Photovoltaic (PV) paired with storage, with smart-inverter Volt/VAR and Volt/Watt functions
- Managed electric vehicles charging and Vehicle-to-Grid in constrained pockets
- Dispatchable DER where appropriate
- Interruptible/curtailable load tariffs
- Community microgrid with islanding capability
- Conservation Voltage Reduction/Volt/VAR Optimization and reactive power support (e.g. via Battery Electric ESS/PV) for voltage/hosting constraints
- Auto-transfer + Fault, Location, Isolation and Service Restoration leveraging existing DER

These NWS categories may be configured to address a range of need types, such as capacity relief at constrained stations, reliability improvement on long radial feeders with elevated SAIDI, urban pockets short of transfer/back-up capacity, high-PV subdivisions and long feeders exhibiting low voltage at summer peak, and urban network areas with elevated technical losses.

D Gate-Based Screening Process

The NWS Framework employes a staged, principles-based screening process to determine whether an NWS is a preferred alternative to a traditional wires investment. It is intended to integrate NWS consideration early in planning, provide transparent decision records, and remain flexible as OEB policy, market depth, and enabling systems evolve. For this DSP, the NWS Framework is comprised of a four-gate process that progresses from high-level suitability screening through feasibility confirmation to economic analysis. Table 5.3.5 - 1 summarizes each gate.

Alectra Utilities will develop detailed checklists and decision matrices as internal planning processes and refine over time as the process matures.

Table 5.3.5 - 1 Overview of the NWS Gate Screening Process

Gate	Screen	Purpose
Gate 0	Portfolio Pre-Screen	Question: Is the primary driver of the need one that an NWS could address? Triage system needs whose primary driver can only be satisfied by wires solution.
Gate 1	Binary Screen	Question: Are there considerations that preclude NWS at the outset? Exclude needs that must proceed as wires owing to safety, mandate, insufficient time-to-need, and costs
Gate 2	Technical Feasibility	Question: Is it technically feasible for an NWS to address the system need? NWS can reliably satisfy the need, at reasonable cost, with no material impeding barriers
Gate 3	BCA & Engineering	Question: Does BCA and an appropriate and reasonable delivery plan support proceeding with an NWS? Refined engineering, reliability and cost estimates for both NWS and wires, Benefit-Cost Analysis

Gate 0: Portfolio Pre-Screen

Gate 0 determines at the earliest stage whether the primary driver of the need can be met by an NWS. Needs that are inherently incompatible with NWS proceed directly to a wires solution.

Table 5.3.5 - 2 maps the primary drivers to Gate 0 rationale. The needs whose primary driver satisfies the criteria proceed to Gate 1 – Binary NWS Screen.

Table 5.3.5 - 2 Gate 0 Decision Matrix

Investment Category	Primary Driver (per Table 5.3.5 - 1)	Rationale
System Access	Customer service requests (new connections, modifications, expansions)	Statutory obligation to provide physical connection; cannot be met by DER or demand response. NWS considered if fully paid by the customer
	Other third-party infrastructure development (e.g. relocations for road widening)	Work is mandated by external party; NWS cannot substitute the physical relocation.
	Mandated service obligations (Distribution System Code, Conditions of Service, metering, long-term load transfer resolution)	Compliance requirement; solution must be wires-based or metering equipment.
System Renewal	End-of-life replacement / failure / high performance risk / functional obsolescence	Driver is asset health; NWS does not rehabilitate or replace deteriorated asset.
System Service	Expected changes in load that will constrain service delivery (capacity upgrades, line extensions, property acquisition)	Classic NWS use-case; peak-shaving, storage, or other DERs can defer or avoid traditional reinforcement.
	System operational objectives – safety, reliability, power quality, efficiency, other performance/functionality	Eligible where the shortfall can plausibly be met by NWS.
General Plant	System capital-investment support, system-maintenance support, business-operations efficiency, non-system physical plant	Expenditures are not made on the electrical system itself.

Gate 1: Binary Screen

Gate 1 confirms whether an NWS can reasonably be considered for the identified need. The system need advances to Gate 2 – Technical Feasibility based on short Yes/No set of considerations.

The Binary Screen considerations include:

- *Safety and emergency restoration:* If there is an imminent public/worker safety hazard or unplanned emergency rebuild
- *Non-discretionary compliance and mandates:* If system needs are driven statutory, code, or compliance obligations
- *Planning context and interdependencies:* Where IRRPs indicate a wires solution, or where feeder-station interdependencies make NWS impractical
- *Time-to-need:* If there is insufficient lead time to design, solicit, contract, and commission an NWS portfolio without risking service
- *Materiality:* If the wires solution doesn't exceed the $2MM threshold set in BCA Framework[90]
- *Customer funded*, if the primary driver is a specific customer connection request with a consent to participate and fund NWS study

Gate 2: Technical Feasibility

Gate 2 determines whether an NWS portfolio can reliability satisfy the need without material impeding barriers. System needs with a technically feasible NWS portfolio advance to Gate 3 – BCA & Engineering.

The Technical Feasibility considerations include:

- *Magnitude and duty cycle*: Whether the candidate NWS portfolio could supply or offset most of the required need (MW/MWh), sustain the output for the required duty, and defer the wires work by several years
- *Performance and operability:* Whether the NWS portfolio could meet required time (instant/seconds/minutes/scheduled) and comply with power-quality limits, fault-ride-through, anti-islanding, and protection-coordination requirements

[90] BCA Framework, p. 8.

- *Siting and permitting:* Whether there is an absence of fatal barriers (municipal zoning, noise limits, heritage, endangered species) to installing and operating the NWS resource at the necessary scale and location
- *Market depth and delivery risk:* Whether qualified vendors/customers exist and can deliver within the planning window
- *Cost reasonableness*, whether the preliminary estimates indicate that the NWS portfolio's cost envelope is broadly commensurate with the cost of traditional wires solution and is not prohibitive

Gate 3: BCA and Engineering

The objective of Gate 3 is to confirm whether the BCA and an appropriate, reasonable delivery plan support proceeding with an NWS, and to demonstrate that the NWS portfolio delivers equal or greater Net Present Value (NPV) to ratepayers than the traditional wires alternative, or is sufficiently close that documented qualitative benefits justify proceeding.

The Gate includes:

- Application of the OEB BCA Framework with scenario and sensitivity analysis to account for uncertainty in DER performance, pricing and technical and economic parameters
- Proposed procurement pathway (e.g. tenders, local auctions), market scan, commercial terms, coordination with the IESO and IESO programs where applicable
- Implementation plan with critical path, decision triggers, and contingency/backstop to the wires alternative if market outcomes diverge
- Cost recovery and incentives with the intended cost-recovery approach and any incentive constructs proposed in accordance with OEB filing guidelines and codes for subsequent OEB review and approvals
- Public-engagement, including stakeholder meetings, community outreach, Indigenous consultations

Gate 3 completes the NWS Framework. Where the evidence supports proceeding (e.g. positive or near-breakeven Distribution Service Test (DST) with qualitative support), the NWS is advanced for approval.

Scalability and Continuous Improvement

The NWS Framework is designed to evolve as:

- Additional data on local DER potential for each Operating Area, performance, and pricing become available
- Foundational investments in system visibility and DER integration mature
- The regulatory environment continues to advance

This NWS Framework enables Alectra Utilities to screen system needs consistently and effectively ahead of the OEB's mandatory application of the BCA Framework in 2026, while building a track record that will inform future refinements and full-scale implementation in the future. Alectra Utilities will configure its existing Copperleaf optimization platform and evolve its capital planning process to incorporate NWS screening inputs and BCA parameters to consider NWS within the same decision-support environment used for capital planning & optimization.

5.3.5.5 NWS Framework Application in this DSP

Alectra Utilities applied its preliminary NWS Framework to capacity-driven capital projects in the DSP and determined that the needs at five station areas (Newton TS, Nebo TS, Barrie MS, Melbourne MS, and Alliston MS) are suitable candidates for appropriately scoped NWS portfolios during the plan term (refer to *Appendix B13 – Stations Capacity* for station-level detail and timing). At the MS level, NWS provides localized capacity relief and contingency coverage to maintain the N-1 standard, while at the TS level NWS enables Alectra to bridge larger regional gaps, defer high-cost transmission builds to make them optimally timed and right-size otherwise necessary station investments while maintaining safe and reliable service.

A Scope of Capital Projects Assessed

The review focused on two investment programs with direct capacity implications:

- Lines Capacity Program (refer to *Appendix B12 – Lines Capacity*): 39 projects to relieve feeder loading, improve voltage profiles, or integrate new customer demand.
  - 17 of the Lines Capacity projects are linked to corresponding Station Capacity needs and were assessed jointly (a feeder build typically follows a station expansion, making independent deferral via NWS impractical).
  - The remaining 22 Lines Capacity projects were evaluated separately.
- Stations Capacity Program (refer to *Appendix B13 – Stations Capacity*)
  - 30 station-level projects (e.g. transformer station expansions or upgrades to address area load growth or enhance reliability) were evaluated for potential application of NWS.

B Results of NWS Screening

Using the principle-based gates in the NWS Framework:

- Lines Capacity: no feasible NWS was identified
- Stations Capacity: Five TS/MS stations (encompassing five stations capacity, three land acquisitions, and four materials lines projects connected to five stations) were advanced to BCA and Engineering gate

The preliminary BCA results indicated positive economics under conservative assumptions, supporting a deferral path during the DSP Period.

As described in *Section 5.3.5.1*, Alectra Utilities has deferred these five projects on the assumption that it will be possible to procure DER sufficient to cost-effectively and reliably meet the capacity need during the DSP forecast period. The viability of NWS to defer the stations projects is subject to considerable sensitivity with respect to DER pricing, duration of deferral, and dispatch certainty. Given these uncertainties, Alectra Utilities has not included the NWS OM&A costs in the revenue requirement forecast in this application. Instead, the company proposes to establish a Non-Wires Solutions Deferral Account (NWSDA) to record the actual prudent costs of acquiring DERs during and operating and managing the NWS program during the 2027-2031 period, for subsequent OEB review and disposition (refer to *Exhibit 9, Tab 8, Schedule 1*

Establishment of New Deferral and Variance Accounts). This approach to NWS provides value to customers, through the deferral of otherwise necessary capacity investments, while allowing the company a mechanism to recover the cost of procuring and operating necessary DERs, subject to OEB review.

Project-specific results and rationale are provided in *Section 5.2* of *Appendix B12 - Lines Capacity* and *Appendix B13 - Stations Capacity*.

C NWS Program

Alectra Utilities plans to implement an NWS Program during the 2027-2031 period to procure third-party DER capacity and energy in the five affected pockets: Nebo TS, Newton TS, Melbourne MS, Alliston MS, and Barrie MS. This NWS Program will provide locational capacity relief and thereby defer or right-size otherwise necessary station investments.

The program will be technology-neutral and competitively sourced, with portfolios composed of various NWS such as demand response, battery storage and other eligible DERs, configured to the characteristics of the capacity constraints. The commitment period will run from May 1 to October 30 to match capacity peaks.

Alectra Utilities plans to meet an aggregate capacity-relief need of approximately 24-26MW in 2030-2031, aggregated from the station-specific capacity gaps at Nebo TS, Newton TS, Melbourne MS, Alliston MS, and Barrie MS. Including a 22% DER reliability margin[91], Alectra Utilities targets approximately 30-32MW of subscribed capacity. For planning purposes, Alectra Utilities applies commercial parameters informed by the demonstration experience in the York Region pilot: a capacity price of $400/kW-day (2022$) and an energy price of $2/kWh (2022$). On this basis, Alectra Utilities estimates the following payments to third-party DER providers over the DSP Period (refer to Table 5.3.5 - 3).

[91] Assumed DER Reliability margin in the Base Case scenario (based on actual DER performance measurements). IESO York Region Non – Wires Alternatives Demonstration Project Evaluation Report, July 2024, p.49.

Table 5.3.5 - 3 NWS Program Parameters

Year	Aggregate Need (MW)	Targeted Capacity incl. DER Reliability Margin (MW)	DER Payments ($MM)
2027	8.9	10.9	1.1
2028	13.6	16.6	1.7
2029	19.3	23.6	2.5
2030	26.3	32.1	3.4
2031	24.4	29.7	3.3
Total			**12.0**

Total payments to third-party DER owners over the DSP Period are estimated to be approximately $12.0MM. Expressed in 2025 dollars, the Net Present Value (NPV) of total payments over the same period is $8.7MM.

Consistent with the OEB's proposed DSC amendments[92] and filing guidelines[93], Alectra Utilities proposes to apply a 25% Margin on Payments to qualifying third-party DER payments. The indicative MoP NPV over the same period is approximately $2.2MM (2025).

Alectra Utilities plans to advance the NWS Program through locational market engagement: RFI/RFP/RFQ and local auctions, timed to the enabling-infrastructure investments described in *Appendix B14 - Enabling Resiliency and Modernization* and the need timing in *Appendix B13 – Stations Capacity*. Alectra Utilities will track by year, subscription levels, cleared prices, test results, call statistics and realized performance against the utilization assumptions, and will file appropriate records to support the OEB's review of amounts recorded in the NWSDA, including reconciliations of DER payments, any approved MoP amounts, and NWS Program OM&A with accompanying evaluation, measurement and verification results (refer to *Exhibit 9, Tab 8, Schedule 1 Establishment of New Deferral and Variance Accounts*). This staged NWS approach is intended to deliver measurable customer value through near-term deferral of capital works while maintaining clear safeguards and transparency for customers.

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[92] EB-2025-0083. Notice of Proposal to Amend a Code. Proposed amendments to the Distribution System Code regarding a margin on payment incentive mechanism for the use of third-party distributed energy resources as non-wires solutions, May 16, 2025.

[93] Filing Guidelines for Incentives for Electricity Distributors to Use Third-Party DERs as Non-Wires Alternatives, March 28, 2023.

D Coordination with IESO – eDSM Framework

In addition to the location-specific NWS Program, Alectra Utilities will also coordinate with the IESO's multi-year Electricity Demand-Side Management (eDSM) framework (2025-2036) to advance province-led efficiency and demand-response actions. This coordination is expected, over time, to mitigate overall pressure on capacity constraints across Alectra Utilities' service territory and will be reflected in Regional Planning, including the IRRPs.

Alectra Utilities will support the IESO's eDSM Framework by:

- Promoting IESO energy-efficiency programs, particularly for Industrial Conservation Initiative customers, to serve as building blocks for future Alectra Utilities-led NWS offerings
- Advancing customer-engagement and marketing activities (Stream 1) to increase awareness, brand, and trust
- Working toward the IESO energy-efficiency target of 280GWh set for all LDCs over the framework term

5.4 Capital Expenditure Plan

5.4.1 Capital Expenditure Summary

5.4.1.1 Introduction

This schedule summarizes Alectra Utilities' capital expenditures over a 12-year period, including five historical years (2020-2024), two bridge years (2025-2026), and five forecast years (2027-2031). Alectra Utilities' investments align with system needs, customer expectations, and statutory requirements. Key highlights include a 5-year plan versus actual comparison for the historical period, highlights of the bridge year planned investments, and a comparison of forecast versus historical expenditures across OEB-defined investment categories.

In this Distribution System Plan (DSP), Alectra Utilities is focused on the investments necessary to achieve three objectives:

- **Renewing & Replacing Deteriorated Infrastructure**: Ensuring reliable, safe, and dependable assets and infrastructure
- **Meeting Growing Electricity Demand**: Prudently preparing the grid for anticipated growth and electrification
- **Enabling Resiliency & Modernization:** Increasing system uptime and performance against adverse weather and communicating effectively with customers

The plan is developed to maintain assets that:

- Deliver sustainable value
- Mitigate risks
- Comply with regulations, codes, and standards, and
- Achieve performance targets

Supporting documentation is provided, including OEB Exhibit 2B, Appendix 2-AA (refer to Table 5.4.1 - 8) and OEB Appendix 2-AB (refer to Table 5.4.1 - 2), which provide a 12-year summary of capital expenditures. Alectra Utilities confirms that there are no expenditures for non-distribution activities in the capital expenditures plan.

During 2020-2024, Alectra Utilities strategically allocated available resources among asset renewal needs, emerging customer demand, and evolving operational requirements to effectively mitigate reliability risks and ensure expenditures deliver value, meet strategic objectives, and comply with regulatory requirements.

The DSP is a balanced and forward-looking capital investment plan, with investments made to address immediate and emerging needs during the forecast period. Expenditures for Capital projects with a duration greater than one year are recorded in Construction Work-in Progress (CWIP) until the work is completed, at which point the expenditures become capitalized in accordance with the Capitalization policy included in Exhibit 2B, Tab 7, Schedule 1.

The sections below outline the key issues and challenges faced by Alectra Utilities, as well as a discussion on historical expenditure and current needs, which the Distribution System Plan for 2027-2031 addresses.

5.4.1.2 Implementation of 2020 OEB Decision

Alectra Utilities' distribution rates have not been rebased since the company was formed, though the company did submit a DSP covering its planned expenditures for the 2020-2024 period in its 2020 annual rate-setting application (EB-2019-0018). Although the application (EB-2019-0018) laid out an investment roadmap averaging $291MM per year, available funding through base rates supported only $236MM annually. Between 2020 and 2024, Alectra Utilities carried out its capital investment plan guided by trade-offs between needs and available funding, supplemented by additional support through the OEB's Incremental Capital Module (ICM).

Throughout the 2020-2024 period, Alectra Utilities faced continuous challenges of aligning its capital investment needs with available funding, with the overall spending accumulating to $1.5B during this period. Each year, this required a strategic evaluation of planned projects to determine where limited resources could be optimized. Given the complexity of the system's needs, particularly for underground infrastructure renewal, this was a challenging exercise, often involving the reprioritization of work to ensure that the most critical investments could proceed.

Capital spending was carefully reprioritized each year to address the highest-risk assets and maintain essential system performance. The pace of infrastructure deterioration across multiple asset classes, especially in the underground system, continues to outpace current investment levels. Alectra Utilities managed the immediate asset failure risks in the system by targeting deteriorating hot spots at the expense of future systemic asset failure risks due to aging equipment. Alectra Utilities need to increase funding to key areas in the 2027-2031 period to ensure the increasing backlog of deteriorating infrastructure is managed and the long-term reliability of the distribution system is maintained.

To manage available resources to meet critical infrastructure needs and objectives, Alectra Utilities invested an additional $40.2MM in the distribution system through multiple ICM applications (EB-2020-0002, EB-2022-0013, EB-2023-0004), thereby increasing the total available funding. These investments were supported by the need and urgency identified in Alectra Utilities' project proposals, ensuring critical upgrades and expansions were funded to improve service delivery to customers. In addition to the approved ICM projects, Alectra Utilities undertook an additional $8.4MM in spending to complement the OEB's approved ICM projects.

5.4.1.3 2020-2024 Investment Analysis

Alectra Utilities' total capital expenditures over the historical period present a compound annual growth rate (CAGR) of 2.2%, indicative of a modest and measured investment approach. This modest growth reflects a deliberate strategy to balance infrastructure needs with cost management, while continuing to meet customer demands. Pressures from inflation, supply chain disruptions, continued customer growth and evolving system demands were managed while ensuring that resources were directed to immediate needs.

A Primary Drivers of Capital Expenditures between 2020 and 2024

A.1 Infrastructure Renewal Investments

Alectra Utilities has made substantial investments to maintain reliability and resilience and mitigate other risks, largely focusing on both overhead and underground asset renewal. Alectra Utilities obtained additional funding for necessary investments with ICM applications focused on critical underground asset renewal projects. Over the 2020 to 2024 period Alectra Utilities completed 51 cable replacement projects and 57 cable injection projects. Ongoing deteriorating assets, largely related to underground infrastructure, contribute to nearly half of the controllable outages. The current volume of deteriorating assets continues to grow, thereby increasing systemic failure risks that could have safety, reliability and environmental impacts.

A.2 Customer Demand and Growth

Ongoing customer growth and requirements to support expansion projects have necessitated the need to enhance service levels and invest in infrastructure expansion to accommodate increased customer loads and ensure efficient service delivery. Historical expenditures for customer-driven work have increased largely due to volume and substantial expansion projects initiated by customers. This increase has been driven by various developments within Alectra Utilities' service territories, particularly in the Alectra Utilities Central and Alectra Utilities East regions. Many of these developments have high load forecasts, resulting in lower (relative) financial contributions from customers, and higher Alectra Utilities net capital costs. The overall surge in customer connections has increased historical expenditures above the initial plan.

A.3 Automation and Operational Efficiencies

Substantial investments have been made towards grid modernization and automation, including upgrades to SCADA communications systems. These have helped to improve grid reliability and resilience by enabling precise and real time fault detection and restorations. These investments have directly contributed to reducing outage duration and minimizing the impact of outages on customers. Additionally, Alectra Utilities invested in a centralized Operations hub to improve efficiencies. This replaced two outdated and separate facilities. This centralized hub aligned with the company's financial objectives of increasing cost effectiveness, improved cross-functional collaboration, reduced operating and overhead costs, and improved service responsiveness in the Central Region serving Mississauga and Brampton.

Significant investments were also made in Information Technology Systems, with major initiatives including a Meter-to-Cash upgrade program, Customer to Meter (C2M) migration and a modernized Customer Service platform. The Customer Service Strategy project enables visibility into customer consumption in real time, as well as billing and payment data in a single platform, all aiming to increase operational efficiencies.

Table 5.4.1 - 1 Alectra Utilities Historical Capital Summary

Category	2020 Actual			2021 Actual			2022 Actual			2023 Actual			2024 Actual			5-Year Actual		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var
	$MM		%	$MM		%	$MM		%	$MM		%	$MM		%	$MM		%
System Access	66.5	63.1	-5%	66.9	67.4	1%	63.2	47.4	-25%	67.1	67.3	0%	70.2	101.8	45%	333.9	347.0	4%
System Renewal	139.0	135.5	-3%	142.0	136.5	-4%	154.0	134.1	-13%	156.1	164.4	5%	177.2	172.7	-3%	768.3	743.2	-3%
System Service	38.0	26.8	-29%	36.9	28.4	-23%	36.0	24.3	-33%	42.4	18.6	-56%	37.2	22.7	-39%	190.5	120.8	-37%
General Plant	39.4	33.5	-15%	34.4	37.8	10%	35.1	59.8	70%	30.2	78.2	159%	24.7	36.1	46%	163.8	245.4	50%
Total	**282.9**	**258.9**	**-8%**	**280.2**	**270.1**	**-4%**	**288.3**	**265.6**	**-8%**	**295.8**	**328.5**	**11%**	**309.3**	**333.3**	**8%**	**1,456.5**	**1,456.4**	**0%**

B System Access 2020-2024 Investment Analysis

During the 2020-2024 period, System Access investments were $347.0MM which is 24% of the overall Capital portfolio. Investments in this area were $13.1MM or 4% higher than the planned expenditures of $333.9MM. Customer connections accounted for $201.0MM or 58% of the total System Access expenditures which was higher than plan by $27.7MM or 16% due to customer-driven system expansion work.

This included transit upgrades and subdivision and commercial development within Alectra Utilities service area. These large customer projects often exceeded historical norms, requiring adjustment to resource allocations. Investments in metering for $84.9MM or 24% of total System Access expenditures, were higher than plan by $21.8MM or 35% largely driven by new meter connections and upgrades, meter renewals and initiating the next-generation metering AMI 2.0 rollout.

Hydro One transmitter upgrades fluctuated, initially seeing lower expenditures due to timeline adjustments, but increased towards the latter part of the period as timelines were realigned, resulting in higher expenditures by $1.8MM or 64%. Road Authority work was lower by $38.2MM or 40%, mainly as projects were significantly deferred and reduced in scope as funding frameworks and municipal schedules were realigned.

B.1 Customer Connections

Investments in Customer Connections were $201.0MM through 2020-2024 and contributed to 58% of all investments in System Access. Investments in this area focused on new residential developments and system expansions to accommodate growing electricity demand. Expenditures in this area were largely driven by the need to support fast-growing subdivisions and ICI customers. Alectra Utilities energized roughly 5,200 new subdivision lots each year and more than 1,200 ICI connections were added from 2020-2024. These investments originated from customer requests and supported supplying connections to industrial, commercial and institutional customers such as medical buildings, small plazas and factories.

Customer-initiated expansion and relocation projects also contributed significantly to System Access expenditures. These projects are driven by requests from developers, municipalities, or large customers who require distribution assets relocated, or system expansion. Over the historical period, expenditures accelerated after 2023 with large expansion projects across most regions as well as large transit related expansion projects for feeder upgrades.

B.2 Network Metering

Investments in Network Metering were $84.9MM through 2020-2024 and contributed to 24% of all investments in System Access. The largest proportion of expenditures was allocated to New Connections & Upgrades required to connect new customers within its service territory. This accommodated 5,500 single-phase and 800 polyphase meters to be installed each year to keep pace with customer growth.

The Meter Failure programs required significant investments to replace failed meters to maintain reliable and accurate customer billing. Failed meters were replaced within five business days in over 90% of cases, in response to overall failure rates that were roughly 1%. This prevented billing gaps and risks from materializing.

Lastly, the AMI Renewal program required investments for marking the initial phases of planning and small-scale deployment, for which 38,000 AMI 2.0 meters were installed, along with investments in associated network infrastructure to position Alectra Utilities for the broader AMI 2.0 rollout in the next plan period.

B.3 Road Authority

Investments in Road Authority related projects were $56.5MM through 2020-2024 and contributed to 16% of all investments in System Access. This category of investments requires Alectra Utilities to relocate or reconstruct electrical infrastructure located in or around public roads as outlined in the *Public Service Works on Highways Act*. Projects within this category are subject to timeline changes, scope changes and deferrals because of changes from Municipal planning cycles. This requires Alectra Utilities to adjust plans to accommodate requests or deferrals for such work. Alectra Utilities experienced a reduction in executable work in this category compared to initial forecasts, in large part, due to the reassessment and delays in road infrastructure plans from the municipalities within Alectra Utilities' territory.

C System Renewal 2020-2024 Investment Analysis

During the 2020-2024 period, System Renewal investments were $743.2MM which is 51% of the overall Capital portfolio. Investments in this area were within $25.1MM or 3% of planned expenditures of ($768.3MM). System Renewal investments continued to be a challenge due to the increasing rate of deteriorating assets and the rising reactive capital needs, which required the reallocation of available funds.

Investments in Underground related categories accounted for $308.8MM or 42% of the total System Renewal expenditures. These investments reflect a significant emphasis on the renewal of aging underground cables to prevent outages and improve service reliability. However, the overall current pace of renewal falls well short of what is required in the medium to long term, as the growing volume of assets in poor to very poor condition poses an increasing and substantial risk of significant future failures.

Reactive expenditures were $156.7MM which accounted for 21% of total System Renewal expenditures. These expenditures exceeded the plan by $58.7MM or 60%, highlighting the urgent need to address increasing failures. The increase in these expenditures required careful allocation of resources across key asset classes, including poles, transformers, cables, and switchgear to ensure reliability is maintained.

Renewal expenditures for overhead assets, transformers, and substation infrastructure were $274.0MM which accounts for 37% of the total System Renewal investments. These reflect the ongoing focused spending by Alectra Utilities towards ensuring its infrastructure is operating safely and reliably.

C.1 Underground Asset Renewal

Investments in Underground Asset Renewal were $308.8MM through 2020-2024 and contributed to 42% of all spending in System Renewal. Investments in this area are largely driven by the growing volume of deteriorated cables, which are a major contributing factor to equipment failures and outages, accounting for 41% of all equipment-related outages. Ongoing cable failures increase concerns regarding overall reliability, where 55% of customer hour interruptions were due to underground equipment related failures, including cables and switchgear.

Alectra Utilities applied for ICM funding to target critical areas in 2023 and 2024 for cable replacement and injection. However, even with those additional investments of $37.8MM, the deterioration of cables continues to outpace the rate of renewal. Overall assessment of the underground infrastructure demonstrates an ongoing increase in Poor and Very Poor cables, highlighting further need for immediate and continuous ramp up in investments going forward.

Further challenging matters, Alectra Utilities is experiencing a dwindling number of cables that are candidates for cable rejuvenation to remediate cable deterioration and postpone cable replacement. By 2030, cable replacement will be the only viable option for remediating deteriorated cable. This option comes at an increased cost.

C.2 Overhead Asset Renewal

Investments in Overhead Asset Renewal were $193.1MM through 2020-2024 and contributed to 26% of all investments in System Renewal. Investments in this area were largely driven by the need to address aging infrastructure, which significantly affected system reliability and caused frequent outages. Equipment failures were a major concern, accounting for 44% (MED excluded) of total Customer Hours of Interruption (CHI), with overhead line hardware failures resulting in an average of 199 outages per year and contributing to 81,228 CHI annually. The work mainly focused on programs to remediate overhead poles, voltage conversion, and renew switches that were negatively affecting system control. These investments were critical to ensuring the safe and reliable operation of the overhead distribution system. The expenditures contributed to key metrics such as SAIDI and SAIFI to improve.

C.3 Reactive Replacements

Investments in Reactive Capital were $156.7MM through 2020-2024 and contributed 21% of all investments in System Renewal. Investments in this area were largely driven by the need to promptly address urgent equipment failures, damage from severe weather events, and foreign interference incidents. During this period, expenditures for failed equipment were the largest contributor, with 82% of total reactive spending. This addressed failing switchgear issues, cable faults, and leaking transformers that needed urgent replacement. Further expenditures were incurred related to foreign-interference events to address instances of accidents, vandalized hardware, and theft. Multiple severe adverse weather events occurred mainly storms, tornadoes, and floods. In 2022, a Derecho swept across Alectra Utilities with wind gusts of 120KM/h, impacting one-third of all customers and resulting in over 100 poles being reactively replaced.

C.4 Transformer Replacements

Investments in Transformer Renewal were $40.3MM through 2020-2024 and contributed to 5% of all investments in System Renewal. Investments in Transformer renewal continue to increase year-over-year as Alectra Utilities works to tackle the increasing number of Poor or Very Poor condition transformers throughout the distribution system. The 2023 Asset Condition Assessment demonstrates an increase of over 215% in the number of deteriorated transformers requiring replacement from 2018-2023. As of 2023, there were over 9,000 such transformers in deteriorated condition. Investments throughout 2020-2024 were accelerated to address deterioration, which helped to mitigate environment (oil leaks), public safety, and reliability (prolonged outages) risks.

D System Service 2020-2024 Investment Analysis

During the 2020-2024 period, System Service investments were $120.8MM which is 8% of the overall Capital portfolio. Investments in this area were $69.7MM or 37% lower than the planned expenditures of $190.5MM. Project deferral of lines capacity projects was a leading contributor to the underspending variance and enabled Alectra Utilities to address other high priority renewal needs.

Alectra Utilities invested heavily in SCADA & Automation and System Control & Communications totaling $60.7MM, which was higher than planned by $17.5MM or 41%. This overspend was driven by the need to mitigate the impacts of failed equipment on customers by reducing outage duration. The increased focus on automation provided faster fault detection, real-time monitoring, and improved system control, all of which reduced outage duration. However, while automation enhances operational performance, it does not prevent the outage from happening. Automation can help reliability duration metrics but will not prevent events from occurring. Renewal of deteriorated assets infrastructure is necessary for maintaining a reliable grid.

D.1 SCADA & Automation and System Control & Communication

Investments in SCADA & Automation and System Control & Communications were $60.7MM through 2020-2024 and contributed 50% of all investments in System Service. The investments of $38.3MM in Automation were primarily aimed at replacing manual switches with SCADA-enabled devices compatible with the Distribution Automation (DA) switches, as well as installing new switches and reclosers to support the overall program. Through the acceleration of the program in the historical period, Alectra Utilities installed SCADA-ready switches and reclosers. This faster pace of installation resulted in reliability gains through better fault detection and quicker restoration, establishing a strong foundation for future automation and grid resiliency. Additionally, Alectra Utilities invested $22.4MM to renew critical protection and control assets at transformer and municipal stations. These investments support the deployment and renewal of communications infrastructure, including WiMAX and LN900 MHz systems, enhancing system reliability and operational effectiveness.

D.2 Lines Capacity

Investments in Lines Capacity were $39.3MM through 2020-2024 and contributed to 33% of all investments in System Service. These investments were primarily aimed at upgrading feeders to support growth.

Key projects included four large feeder builds including the Hamilton South Mountain capacity-relief project, which added a new feeder and re-balanced the overloaded Horning and Nebo circuits; the Bunting M81 extension in St. Catharines, extending an under-used feeder to ease Carlton and Bunting lines; Vaughan TS#4 feeder integration, linking two new 27.6kV feeders to serve Kleinberg and Vaughan West; and the Waterdown 3rd feeder in Hamilton, boosting capacity for a growing community and several large customers.

Multiple Lines capacity projects were postponed mostly due to reprioritising funds to urgent renewal needs and in some cases changes in timelines and plans associated with road infrastructure projects and other municipality driven projects. Deferral of these investments has delayed Alectra Utilities' ability to respond to increasing load growth, requiring larger capacity expansion planned for 2027-2031.

E General Plant 2020-2024 Investment Analysis

During the 2020-2024 period, General Plant investments were $245.4MM which is 17% of the overall Capital portfolio. Investments in this area were $81.6MM or 50% higher than the planned expenditures of $163.8MM. Investments of $100.0MM were directed to Facilities Management, for which a large portion is attributable to the new Operations (service) Centre at Kennedy Road.

This project was initiated to replace two aging, inefficient and constrained operations centres at Mavis Road and Sandalwood Parkway. While the development required a substantial initial investment, it provides long-term value by providing a safe, scalable and modern operational hub that reduced costs, supports future growth, and eliminates the risks associated with the previous sites (refer to *Appendix B07 - Facilities Management, Section VII* for further details on the project and supporting analysis).

Additional investments of $98.8MM were made towards IT infrastructure, which were critical to enhancing technological capabilities and supporting business operations. Alectra Utilities significantly invested in Customer Service Technologies, which required extended discovery and build phases to accommodate diverse customer scenarios. This helped to support advanced functionality like real-time usage, billing, and payments data.

The total fleet renewal investments were $33.1MM which were lower than the plan largely due to supply chain delays during and after the COVID–19 pandemic.

E.1 Facilities and Fleet

Between 2020 and 2024, Alectra Utilities invested approximately $100.0MM in Facilities Management, representing 41% of all investments in General Plant. The primary purpose of this investment was to address deficiencies at the Mavis Road facility in South Mississauga and the Sandalwood Parkway facility in North Brampton. Both sites were aging, inefficient, and no longer suitable for operational needs. They created fragmented operations, limited opportunities for growth, and rising maintenance costs. The Mavis site in particular faced longstanding safety concerns that had only been addressed with temporary measures. Redevelopment of the site would have required relocating operations to a temporary facility at considerable cost and disruption, while also requiring multiple easements and legal approvals. Its proximity to a rail line further limited opportunities for expansion and constrained its ability to accommodate inventory growth. The Sandalwood site also presented significant space limitations, restricting the ability to expand operational capacity. In addition, its location near prospective retail and commercial development created risks related to traffic congestion, security, employee safety and productivity.

To address these deficiencies, Alectra Utilities undertook a comprehensive planning process and evaluated multiple alternatives, including redeveloping the Mavis and Sandalwood facilities. The analysis determined that constructing a new, purpose-built facility at 174 Kennedy Road in the central region of the service territory was the most viable and strategic option. The Kennedy Road facility provided an immediate and permanent solution to the deficiencies of the existing sites by consolidating operations into a modern, centralized location. The new facility improves workplace safety, optimizes space utilization, and reduces long-term operating costs, particularly lease costs previously incurred at the Mavis site. It also provides sufficient land to accommodate inventory growth without requiring additional acquisitions and ensures compliance with the Accessibility for Ontarians with Disabilities Act (AODA), which would have required costly retrofits at the older facilities (refer to *Appendix B07 Facilities Management, Section VII* for further details on the project and supporting analysis).

Other facilities expenditures were also made including replacement of assets that had reached the end of life and fixing building deficiencies that were starting to affect operations. Other facilities in East and West service territories were also upgraded to meet the AODA, with exterior improvements. Further investments were made on LED lighting retrofits, upgrades to HVAC and security systems and removal of hazardous materials.

Alectra Utilities invested $33.1MM in fleet renewal during 2020-2024. Vehicle replacements were based on mileage, condition and age. Light-duty vehicles are typically replaced at 7 years or 250,000 km, while heavy-duty vehicles are replaced at 15 years or 500,000KM. Trailers are assessed at 15 years and prioritized for refurbishment where possible, with replacements considered only when refurbishment is not viable.

E.2 Information Technology

Investments in Information Technology Systems were $98.8MM through 2020-2024 and contributed to 40% of all investments in General Plant. The largest area of investment was the Meter-to-Cash (M2C) Upgrade Program with a total investment of $24.3MM. There were Customer Care and Billing (CC&B) platform enhancements each year, along with the Oracle Customer to Meter (C2M) migration to maintain billing for 1.1 million accounts, as system technical support for CC&B is limited beyond 2026. Another significant area of investment totalling $21.2MM was in Customer Service technologies, aiming to enhance customer engagement through the MyAlectra Utilities portal, web chat and chatbots.

A key objective under the Customer Service Strategy project was to improve real-time outage communications, collections effectiveness, and develop a more user user-friendly bill design. Investments were also made for Business Optimization projects, totalling $12.8MM driven by continuous improvements of the Copperleaf platform to enhance capital planning efficiency. Alectra Utilities invested in continuous improvements to its ERP totalling $8.8MM to maintain reliable core business applications as well as the Core Infrastructure Refresh for essential servers, storage and backup systems. Investments of $8.2MM were also made in End-User Technology to acquire additional hardware needed to support remote work during the pandemic.

5.4.1.4 2025-2026 Bridge Years Investment Summary

During the bridge period of 2025-2026, the planned expenditures total $663.3MM. The average annual planned expenditures for the bridge years are $331.7MM. This represents a 14% increase compared to the historical average from 2020-2024 and is rooted in system and customer needs. System Renewal remains the key area of focus with roughly 48% of total investments at $315.3MM with ongoing attention being placed towards investments in underground cable replacements and injection as well as overhead pole remediation to maintain the system. The plan presents a balanced approach to investments in critical infrastructure during the bridge years while preparing Alectra Utilities for the subsequent years in the DSP plan for 2027-2031.

F.1 System Access

Planned expenditures total $189.1MM during the bridge years. The average annual planned expenditures are $94.6MM. This is higher than the average expenditures over the 2020-2024 period by 36%. This increase is primarily driven by the continuation of large customer-initiated projects, higher subdivision growth activity, along with sustained investment in network metering, (refer to *Appendix B06 – Network Metering* for planned meter volumes). The increase relative to the historical period reflects both regional growth and modernization needs, which will continue into the forecast period.

F.2 System Renewal

Planned expenditures total $315.3MM during the bridge years. The average planned expenditure is $157.7MM annually. This level of spending aligns with the average expenditures over the 2020-2024 period, but represents an increase of 6%. The areas of focus in this category continue to be the renewal of overhead and underground assets. Efforts will continue to be directed towards investments in underground cable as well as essential pole remediation with the aim to maintain system safety and reliability. Cable Injection projects will present a marginally higher investment focus due to larger projects in Hamilton and Mississauga. Overall, the investments are planned to align with the level of expenditures in 2023 and 2024, inclusive of the ICM investments of those years.

F.3 System Service

Planned expenditures total $84.4MM during the bridge years. The average planned expenditures are $42.2MM annually. This is higher than the average expenditures over the 2020-2024 period by 75%. The primary driver of this increase is the need to expand system capacity to serve growing demand across Alectra Utilities' service territory. As a result, the main areas of investment are planned for Lines and Stations capacity projects across Alectra Utilities service areas. Significant projects include Vaughan TS#4 feeder integration and Webb MS station construction, followed by capacity projects such as Vaughan TS#6 and the land acquisition in preparation for a future transformer station at Goreway in Brampton. Other areas of System Service such as SCADA and automation will continue to have sustained levels of investment.

F.4 General Plant

Planned expenditures total $74.5MM during the bridge years. The average planned expenditures are $37.3MM annually. This reflects a decrease from the average expenditures over the 2020-2024 period, by 24%. This is largely because the Kennedy Road project was completed in the historical period. Excluding the Kennedy Road project, the average bridge years is 12% higher than the 2020 – 2024 historical period average. The planned investments will be mainly driven by IT projects, including the ERP upgrade and workforce management projects. Additional investments will also be made in Fleet renewal. The Markham TS#5 project will also be prioritized to ensure Alectra Utilities is sufficiently positioned to support the planned increase in investments during the upcoming 2027-2031 period.

Table 5.4.1 - 2 Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements (OEB Appendix 2-AB)

First year of Forecast Period: 2027

CATEGORY	2020 Actual			2021 Actual			2022 Actual			2023 Actual			2024 Actual		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var
	$MM		%	$MM		%	$MM		%	$MM		%	$MM		%
System Access	66.5	63.1	-5.1%	66.9	67.4	0.7%	63.2	47.4	-25.0%	67.1	67.3	0.3%	70.2	101.8	45.0%
System Renewal	139.0	135.5	-2.5%	142.0	136.5	-3.9%	154.0	134.1	-12.9%	156.1	164.4	5.3%	177.2	172.7	-2.5%
System Service	38.0	26.8	-29.5%	36.9	28.4	-23.0%	36.0	24.3	-32.5%	42.4	18.6	-56.1%	37.2	22.7	-39.0%
General Plant	39.4	33.5	-15.0%	34.4	37.8	9.9%	35.1	59.8	70.4%	30.2	78.2	158.9%	24.7	36.1	46.2%
Total Expenditure	282.9	258.9	-8.5%	280.2	270.1	-3.6%	288.3	265.6	-7.9%	295.8	328.5	11.1%	309.3	333.3	7.8%
System O&M	103.5	110.9	7.1%	104.9	113.1	7.9%	106.4	126.9	19.0%	108.7	123.5	14.0%	110.9	114.9	3.6%

CATEGORY	Bridge Period		Forecast Period				
	2025 Forecast	2026 Forecast	2027 Budget	2028 Budget	2029 Budget	2030 Budget	2031 Budget
	$MM		$MM				
System Access	88.2	100.9	157.7	180.4	164.2	139.1	138.7
System Renewal	157.3	158.0	193.1	209.4	257.3	346.1	362.6
System Service	37.4	47.0	39.2	79.6	150.0	132.0	184.2
General Plant	37.6	36.9	64.8	85.5	82.6	95.9	71.8
Total Expenditure	320.5	342.8	454.8	554.9	654.1	713.1	757.3
System O&M	121.5	122.7	141.3	149.0	155.7	160.2	164.6

Notes to the Table:

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

2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year): 0

Explanatory Notes on Variances (complete only if applicable)

Notes on shifts in forecast vs. historical budgets by category

Refer to DSP Section 5.4.1 for analysis of shifts in forecast vs. historical expenditures by category

Notes on year-over-year plan vs. actual variances for Total Expenditures

Refer to DSP Section 5.4.1 on Variance analysis for between Plan vs Actuals.

Notes on planned vs. actual variance trends for individual expenditure categories

Refer to DSP Section 5.4.1 on Variance analysis for between Plan vs Actuals.

5.4.1.5 2027-2031 Planned versus Historical Expenditures

This section reviews the capital investment levels between Alectra Utilities' historical period (2020-2024), bridge period (2025-2026) and the forecast period (2027-2031). The progression of Alectra Utilities' investments over the historic and bridge periods provides context for the investments that it plans to make over the forecast period to address evolving system needs, customer expectations, and regulatory requirements. The analysis below demonstrates how each investment category contributes to Alectra Utilities' overall capital plan.

Alectra Utilities' average net annual capital expenditures over the seven-year historic and bridge period (2020-2026) are $302.8MM. Investments during this period were largely driven by the need to renew aging infrastructure, with funding prioritized for underground and overhead system renewal, supported by funding provided by the ICM rate riders in later years. Customer growth was a major driver of historic expenditures, particularly the large-scale connections and system expansion projects initiated by commercial and residential developers. Further, operational efficiency needs led to higher required investments in IT systems and facilities, including the consolidation of multiple service buildings into one service centre to streamline field operations and reduce long-term costs. Alectra Utilities continued to advance grid automation through SCADA and communications upgrades to support reliability.

The five-year forecast (2027-2031) average annual capital expenditures of $626.8MM represents a significant increase from the historical annual average. This elevated investment level is necessary to address three priorities over the forecast period:

1. Renewal of deteriorated infrastructure to maintain reliability and safety
2. Meeting growing electricity demands
3. Enabling resiliency while modernizing the distribution system and processes

The key areas of planned investment are outlined in Table 5.4.1 - 3, which presents the average annual increase in planned expenditures compared to the historic results (refer to *Chapter 5.4.2 2027-2031 Investment Overview and Appendix B* for detailed planned capital expenditures in the forecast period).

Table 5.4.1 - 3 Planned and Historic Expenditure Comparison

Planned Investments Compared to Historical Spending	2020-2026 Annual Average ($MM)	2027-2031 Annual Average ($MM)	Planned vs. Historical Annual Average ($MM)
Underground, Overhead and Transformer Renewal	112.1	216.7	104.6
Capacity Lines & Stations	15.0	95.7	80.7
Customer Driven	57.0	95.0	38.0
Network Metering	19.6	61.1	41.5
Information Technology Systems	18.9	29.8	10.9
CCRA	2.4	22.8	20.4
Rear Lot Conversion	0.6	17.3	16.7
Other Capital	77.2	88.5	11.3
Total	**302.8**	**626.9**	**324.1**

'Other Capital' relates to sections not separated in the table above and comprise largely of General Plant, Reactive and Automation investments

A System Access

Table 5.4.1 - 4 System Access: 2020-2031 Expenditures

	Actual Expenditure					Bridge		Forecast Period (Planned)				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
System Access ($MM)	63.1	67.4	47.4	67.3	101.8	88.2	100.9	157.7	180.4	164.2	139.1	138.7

The net annual capital expenditures seven-year average, which includes 5 years (2020–2024) of historical actuals and two bridge years (2025 – 2026) planned expenditures for System Access is $76.6MM. The net capital expenditure five-year forecast average from 2027 to 2031 for System Access is $156.0MM. The planned System Access investments are higher than the historical average largely due to AMI 2.0-meter deployment and higher customer connection projects driven by both higher subdivision growth activity and higher customer related system expansion projects across Alectra Utilities' service territories (refer to *Chapter 5.4.2 2027-2031 Investment Overview* and *Appendix B* for further details regarding the planned capital expenditures in System Access).

B System Renewal

Table 5.4.1 - 5 System Renewal: 2020-2031 Expenditures

	Actual Expenditure					Bridge		Forecast Period (Planned)				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
System Renewal ($MM)	135.5	136.5	134.1	164.4	172.7	157.3	158.0	193.1	209.4	257.3	346.1	362.6

The annual net capital expenditures seven-year average, which includes 5 years (2020-2024) of historical actuals, and two bridge years (2025-2026) planned expenditures for System Renewal is $151.2MM. The net capital expenditure five-year forecast average from 2027 to 2031 for System Renewal is $273.7MM. The planned investments are higher than the historical average largely due to the necessary investment in underground asset renewal, overhead asset renewal, transformer renewal and rear-lot conversion. These expenditures are directed to mitigating risks and to strengthen the distribution system and renew aging infrastructure (refer to *Chapter 5.4.2 2027-2031 Investment Overview and Appendix B* for further details regarding the planned capital expenditures in System Renewal.)

C System Service

Table 5.4.1 - 6 System Service: 2020-2031 Expenditures

	Actual Expenditure					Bridge		Forecast Period (Planned)				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
System Service ($MM)	26.8	28.4	24.3	18.6	22.7	37.4	47.0	39.2	79.6	150.0	132.0	184.2

The annual net capital expenditures seven-year average, which includes 5 years (2020–2024) of historical actuals and two bridge years (2025 – 2026) planned expenditures for System Service is $29.3MM. The planned capital investments for the five-year forecast average from 2027 to 2031 for System Service is $117.0MM. The planned investments are higher than the historical average largely due to additional investments to increase available capacity as well as investments in Distribution automation and modernization of the grid. To meet the forecasted demand in the medium-term, Alectra Utilities will be required to build or expand 11 TSs and 5 MSs in the near-term out of which 3 TSs and 2 MSs are going into service in the current rate period (refer to *Chapter 5.4.2 2027-2031 Investment Overview* and *Appendix B* for further details regarding the planned capital expenditures in System Service).

D General Plant

Table 5.4.1 - 7 General Plant: 2020-2031 Expenditures

	Actual Expenditure					Bridge		Forecast Period (Planned)				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
General Plant ($MM)	33.5	37.8	59.8	78.2	36.1	37.6	36.9	64.8	85.5	82.6	95.9	71.8

The annual net capital expenditures seven-year average, which includes 5 years (2020-2024) of historical actuals, and two bridge years (2025-2026) planned expenditures for General Plant is $45.7MM. The net capital expenditure five-year forecast average from 2027 to 2031 for General Plant increases to $80.1MM. The planned investments are higher due to Capital Cost Recovery Agreement (CCRA) expenditures with Hydro One Networks Inc. (HONI) related to building available capacity, additional investments for fleet for the renewal of aging vehicles and additional vehicles to accommodate the increase in planned investments, and higher information technology expenditures, partially offset by lower facilities expenditures (refer to *Chapter 5.4.2 2027-2031 Investment Overview* and *Appendix B* for further details regarding the planned capital expenditures in General Plant).

In Table 5.4.1 - 8 below, Alectra Utilities provides the OEB Appendix 2-AA which provides capital expenditure information on a project group-specific basis.

Table 5.4.1 - 8 Capital Projects by Group Table (OEB Appendix 2-AA)

Investment Group	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Bridge	2026 Bridge	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
MIFRS												
SYSTEM ACCESS												
Network Metering	17.0	14.3	14.0	16.6	23.0	25.8	26.3	54.1	69.9	68.6	59.8	53.0
Customer Connections	33.8	39.4	27.5	40.3	60.0	47.2	52.7	75.1	91.3	82.4	66.0	72.0
Road Authority & Transit Projects	12.5	13.5	5.9	8.2	16.4	14.4	16.9	23.5	19.2	13.2	13.3	13.7
Transmitter Related Upgrades	-0.2	0.2	0.0	2.2	2.4	0.8	5.0	5.0	0.0	0.0	0.0	0.0
Total SYSTEM ACCESS	**63.1**	**67.4**	**47.4**	**67.3**	**101.8**	**88.2**	**100.9**	**157.7**	**180.4**	**164.2**	**139.1**	**138.7**
SYSTEM RENEWAL												
Overhead Asset Renewal	32.8	39.8	38.7	44.3	37.5	37.7	36.2	58.2	59.7	85.2	90.7	102.5
Reactive Capital	22.5	26.8	34.3	34.2	38.9	32.0	30.5	30.7	28.5	25.2	25.2	25.2
Rear Lot Conversion	2.4	0.1	1.0	0.1	0.1	0.7	0.0	0.0	0.0	20.3	32.7	33.6
Substation Renewal	10.5	7.3	6.5	8.3	8.0	5.1	4.8	7.5	9.6	13.1	14.7	18.7
Transformer Renewal	5.8	6.9	6.7	8.6	12.3	12.0	11.4	16.7	20.6	22.5	29.8	30.5
Underground Asset Renewal	61.5	55.6	46.9	68.9	75.9	69.8	75.1	80.0	91.0	91.0	153.0	152.1
Total SYSTEM RENEWAL	**135.5**	**136.5**	**134.1**	**164.4**	**172.7**	**157.3**	**158.0**	**193.1**	**209.4**	**257.3**	**346.1**	**362.6**

Project Group	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Bridge	2026 Bridge	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
SYSTEM SERVICE												
SCADA & Automation	3.4	9.0	8.7	8.0	9.2	8.3	8.7	8.7	9.2	15.2	21.6	18.1
Capacity (Lines)	11.2	7.0	8.9	6.5	5.7	19.3	6.4	5.2	35.0	63.8	41.9	51.1
Capacity (Stations)	0.7	5.3	0.1	0.3	0.8	4.1	28.5	24.2	25.7	58.8	61.9	110.8
System Control, Communications & Performance	5.5	4.2	4.4	3.3	5.0	3.9	1.8	0.9	9.2	11.0	5.2	3.0
Safety & Security	5.6	2.6	1.9	0.7	1.3	0.2	0.0	0.0	0.2	0.9	1.1	1.1
Distributed Energy Resources (DER) Integration	0.4	0.3	0.3	-0.2	0.7	1.6	1.6	0.2	0.3	0.3	0.3	0.1
Total SYSTEM SERVICE	**26.8**	**28.4**	**24.3**	**18.6**	**22.7**	**37.4**	**47.0**	**39.2**	**79.6**	**150.0**	**132.0**	**184.2**
GENERAL PLANT												
Facilities Management	10.1	10.8	27.9	48.1	3.1	1.1	1.4	2.6	5.6	7.2	6.5	7.4
Information Technology	13.8	13.8	25.8	21.1	24.3	17.3	16.3	26.0	38.4	38.5	22.5	23.6
Fleet Renewal	8.1	6.6	4.0	7.5	6.9	12.1	12.3	24.2	23.3	18.6	17.3	14.5
Connection and Cost Recovery Agreements	0.0	5.5	0.7	0.0	0.0	5.7	5.0	10.0	16.3	16.3	47.5	24.1
Sub-Total	**32.0**	**36.7**	**58.4**	**76.7**	**34.3**	**36.2**	**35.0**	**62.8**	**83.6**	**80.6**	**93.8**	**69.6**
Miscellaneous Projects	1.5	1.1	1.4	1.5	1.8	1.4	1.9	2.0	1.9	2.0	2.1	2.2
Total GENERAL PLANT	**33.5**	**37.8**	**59.8**	**78.2**	**36.1**	**37.6**	**36.9**	**64.8**	**85.5**	**82.6**	**95.9**	**71.8**
Total	**258.9**	**270.1**	**265.6**	**328.5**	**333.3**	**320.5**	**342.8**	**454.8**	**554.9**	**654.1**	**713.1**	**757.3**

Notes:

1 Capital expenditures are provided net of capital contributions.

E Summary of Important Modifications to Typical Capital Programs

Compared to the prior DSP for the 2020-2024 period, Alectra Utilities adapted its capital programs to address the evolving needs of the distribution system as outlined below:

- **Overhead Asset Renewal:** Alectra Utilities plans to increase the pole renewal program and target specific overhead rebuilds to strengthen the overhead infrastructure. Further details are provided in Appendix B01 - Overhead Asset Renewal. In addition, Alectra Utilities has appropriately incorporated the output of the climate risk and vulnerability assessment into its Asset Management Process and developed comprehensive solutions that include infrastructure hardening, including overhead assets. Further details are provided in *Appendix B14 – Enabling Resilience and Modernization*.

- **Underground Asset Renewal:** Alectra Utilities' primary focus on system renewal continues to be addressing deteriorated underground cables. Investment levels for underground renewal need to increase in 2030 and 2031 as the utility concludes the cable injection program and transitions to full cable replacement. Alectra Utilities has determined that the pool of cables is eligible for injection and will exhaust in 2029. Further details in *Appendix B02 - Underground Asset Renewal*.

- **Transformer Renewal:** Alectra Utilities plans to increase transformer renewal investments to address the higher number of at-risk transformers, which increased from the prior DSP period. Further details in *Appendix B03 - Transformer Renewal*.

- **Metering:** Alectra Utilities will replace end-of-life AMI 1.0 meters with AMI 2.0 meters and associated communication equipment to enable accurate billing and advanced functionality for customers and utility operations. Further details are provided in *Appendix B06 – Network Metering*.

5.4.1.6 System Operations & Maintenance

Alectra Utilities' Operations and Maintenance (O&M) programs are fundamental to ensuring the safe, reliable, and efficient operation of Alectra Utilities' distribution system. These programs include Overhead Inspections and Maintenance, Underground Inspections and Maintenance, Stations and Protection & Control, Vegetation Management, and System Control. Each program is designed to mitigate safety risks, sustain asset performance, and ensure service continuity for Alectra Utilities' customers, among other considerations.

As the utility's customer base and size of the distribution system grows, and as modern technologies (e.g. DERs, automation, etc.) add complexity, the operations and maintenance programs will feature prominently in the utility's Asset Management framework. To ensure long-term sustainability and performance, Alectra Utilities is committed to cost-effective programs, which are summarized below.

A Overhead Inspections and Maintenance

This program ensures the continued safety and reliability of Alectra Utilities' overhead distribution system.

Historical Costs & Future Outlook

The average annual spend over the historical period (2020-2024) was $26.7MM. The average annual costs over the forecast period (2027-2031) increase to $33.6MM per year. The increase is approximately 4% per annum over the period, mainly driven by labor costs and maintenance requirements.

Capital Program Influence

Capital investments in overhead renewal, such as pole and switch replacements, mitigate the risk of unplanned costs by reducing the volume of reactive fieldwork and service interruptions, however many of these costs appear as offsets to expected Reactive Capital expenditures, rather than O&M cost reductions. The proposed increased in Distribution Capital investment requires a growing internal resource pool to address the program. This additional labour allows for the completion of Alectra's full maintenance programs (such as the switch maintenance program) and addressing items needing repair (e.g., stolen ground wires, damaged cable guard, loose or broken guy wires, etc.) in a cost-effective manner through work bundling and taking advantage of schedule variability to complete short cycle repair work.

These investments are needed in tandem with the increased System Renewal investment to fully realize the reliability outcomes expected by Alectra customers. Without the increased capital investment, Alectra would not increase its internal labour to the same degree and these repairs and maintenance programs would not be feasible to accomplish at a cost-effective rate.

The addition of new overhead assets through System Service investments expands the number of assets that require asset inspections and preventive maintenance which will result in increased O&M costs to provide ongoing maintenance of these assets. The expected net difference in O&M costs in the Overhead Inspections and Maintenance program as a result of the proposed Capital Program is shown in Table 5.4.1 - 9 below.

Table 5.4.1 - 9 Expected Net Difference in O&M Cost - Overhead Inspections and Maintenance

Year	2027	2028	2029	2030	2031
Cost Difference ($MM)	2.3	3.3	4.1	4.6	5.0

Cost summary of the Overhead Inspections and Maintenance program is shown in Table 5.4.1 - 10.

Table 5.4.1 - 10 Overhead Inspections and Maintenance Cost Summary

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Cost ($MM)	26.5	24.0	30.7	26.1	26.2	28.0	29.1	30.7	32.4	33.9	35.0	36.0

For further details, refer to *Exhibit 4, Tab 2, Schedule 16 Overhead Inspections and Maintenance*.

B Underground Inspections and Maintenance

This program is critical for supporting service reliability in high-density areas where underground assets are prevalent.

Historical Costs & Future Outlook

The average annual spend over the historical period (2020-2024) was $24.9MM. The average annual costs over the forecast period (2027-2031) increases to $30.9MM per year. The increase is approximately 3.9% per annum over the period, mainly driven by labor costs and ongoing maintenance requirements.

Capital Program Influence

Capital programs targeting XLPE cable replacement, transformer and vault rebuilds, and structure upgrades reduce the frequency of recurring failures and costly reactive work, however many of these costs appear as offsets to expected Reactive Capital expenditures, rather than O&M cost reductions. As with Overhead Inspections and Maintenance, the proposed increased in Distribution Capital investment requires a growing internal resource pool to address the program. This additional labour allows Alectra to address items needing repair (e.g., secondary and primary cable faults, damaged bond wires, equipment that have shifted on their foundations, etc.) in a cost-effective manner through work bundling and taking advantage of schedule variability to complete short cycle repair work.

These investments are needed in tandem with the increased System Renewal investment to fully realize the reliability outcomes expected by Alectra customers. Without the increased capital investment, Alectra would not increase its internal labour to the same degree and these repairs and maintenance programs would not be feasible to accomplish at a cost-effective rate.

Like overhead programs, the addition of new modern assets through System Service investments expands the number of assets that require asset inspections and preventive maintenance of underground equipment, which will result in increased O&M costs to provide ongoing maintenance of these assets.

The expected net difference in O&M costs in the Underground Inspections and Maintenance program as a result of the proposed Capital Program is shown in Table 5.4.1 - 11 below.

Table 5.4.1 - 11 Expected Net Difference in O&M Cost - Underground Inspections and Maintenance

Year	2027	2028	2029	2030	2031
Cost Difference ($MM)	0.8	1.6	2.3	2.7	2.9

Cost summary of the Underground Inspections and Maintenance program is shown in Table 5.4.1 - 12.

Table 5.4.1 - 12 Underground Inspections and Maintenance Cost Comparison

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Cost ($MM)	20.9	23.5	29.0	24.9	26.2	25.8	26.4	28.4	29.9	31.2	32.1	33.1

For further details, refer to *Exhibit 4, Tab 2, Schedule 17 Underground Inspections and Maintenance*.

C Stations and Protection & Control

This program ensures the reliability and efficiency of Alectra's stations and protection systems.

Historical Costs & Future Outlook

The average annual spend over the historical period (2020-2024) was $10.0MM. The average annual costs over the forecast period (2027-2031) increases to $14.9MM per year. The increase is approximately 3.1% per annum over the period, mainly driven by headcount increases to support a growing number of assets and telecom network expansions.

Capital Program Influence

Capital investments modernize stations with new assets like transformers and switchgear, which reduce failure risks but do not materially reduce ongoing preventive maintenance needs. The impact of the Capital Program on Station and Protection & Control O&M costs is driven by additional headcount needed to support increased engineering and field activities stemming from the Capital Program, as well as due to the increased maintenance needs driven by planned increases to the Stations and P&C asset bases.

Station and Protection & Control assets are increasing in number thus requiring inspections and preventative maintenance that are contributing to an increase in System O&M (e.g. the number of automated devices is projected to increase from approximately 1,630 in 2024 to approximately 2,340 by 2031). To accommodate growth, Alectra Utilities also proposes to build two transformer stations and one municipal station by 2031. As new stations and equipment are brought online, Alectra Utilities' maintenance program will expand to include these assets in regular inspection and maintenance cycles.

The expected net difference in O&M costs in the Stations and Protection & Control program as a result of the proposed Capital Program is shown in Table 5.4.1 - 5 below.

Table 5.4.1 - 13 Expected Net Difference in O&M Cost - Stations and Protection & Control

Year	2027	2028	2029	2030	2031
Cost Difference ($MM)	0.3	0.2	0.3	0.0	0.1

Cost summary of the Stations and Protection & Control program is shown in Table 5.4.1 - 14.

Table 5.4.1 - 14 Stations and Protection & Control Cost Summary

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Cost ($MM)	8.4	9.0	10.3	11.7	10.4	13.0	13.4	14.0	14.5	15.0	15.4	15.8

For further details, refer to *Exhibit 4, Tab 2, Schedule 10 Stations*.

D Vegetation Management

This program is critical for maintaining system safety and reliability by managing tree growth near utility infrastructure. It includes both cyclical trimming and reactive tree removal.

Historical Costs & Future Outlook

The average annual spend over the historical period (2020-2024) was $5.9MM. The average annual costs over the forecast period (2027-2031) increase to $7.4MM per year. The increase is approximately 2.1% per annum over the period, mainly driven by an increased need to clear vegetation to prevent outages.

Capital Program Influence

While primarily an operational expense, the need for vegetation management is not expected to be materially affected by increased capital expenditures and inflationary costs for contractor service fees are the main driver of increased cost in the Planned Cut Cycle segment, while the primary cost drivers remain external factors like weather and the encroachment of mature trees in the Reactive Tree Trimming Segment.

Table 5.4.1 - 15 Vegetation Management Cost Summary

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Cost ($MM)	5.5	5.3	5.5	7.0	6.2	6.1	6.2	7.1	7.2	7.4	7.5	7.7

For further details, refer to *Exhibit 4, Tab 2, Schedule 15 Vegetation Management*.

E System Control

This program involves operational oversight, switching coordination, and outage management of the distribution system.

Historical Costs & Future Outlook

The average annual spend over the historical period (2020-2024) was $14.5MM. The average annual costs over the forecast period (2027-2031) increases to $16.4MM per year. The increase is approximately 3.9% per annum over the period, mainly driven by staffing needs for an increasingly complex system.

Capital Program Influence

The increased OM&A attributed to the proposed Capital Program is provided below in Table 5.4.1 - 16. The primary driver and therefore the largest variable in determining the resource requirement for System Control Operators is the number of field crews being supported. The proposed increased capital investment plan will require an increased number of field crews which was the primary driver for the Capital Program's influence on System Control O&M costs. In addition, capital investments in advanced monitoring, automation, and control technologies and the integration of Distributed Energy Resources (DER) enhance grid reliability, but also increase the demand for skilled operators to manage increasingly complex systems, driving up operational costs. While these new investments may increase short-term O&M needs, they are offset by long-term reliability improvements and efficiency gains.

Table 5.4.1 - 16 Expected Net Difference in O&M Cost - System Control

Year	2027	2028	2029	2030	2031
Cost Difference ($MM)	0.7	1.0	1.2	1.3	1.4

Cost summary of the System Control program is shown in Table 5.4.1 - 17.

Table 5.4.1 - 17 System Control Cost Summary

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Cost ($MM)	13.3	13.0	13.9	16.4	16.0	13.9	13.4	15.1	16.0	16.5	17.0	17.6

For further details, refer to *Exhibit 4, Tab 2, Schedule 9 System Control*.

5.4.2 2027-2031 Investment Overview

5.4.2.1 Overall Plan

A Overview

Over the 2027-2031 planning period, Alectra Utilities must invest to address increasing system needs related to infrastructure renewal, growth and resilience. Alectra Utilities' planned capital expenditures are required to address these needs, meet government policy objectives, and respond to customer priorities, while making consideration of the rate impact on customers. The focus during the 2027-2031 period is on:

- System Renewal investments to address the large population of deteriorated and failing infrastructure, along with associated safety, reliability, environmental, and other risks
- System Access investments to facilitate effective responses to customer connections and customer-driven expansion requests, and renewing metering infrastructure necessary to support accurate and timely settlement
- System Service investments required to ensure sufficient system capacity to meet the growing energy demands driven by organic growth and electrification
- General Plant investments to ensure operational systems, including IT, facilities, and fleet, which support the operation of the organization remain secure, dependable, and efficient

These investments are critical for effective and efficient delivery of electrical distribution services and to ensure compliance with evolving regulatory and operational standards. Table 5.4.2 - 1 provides a summary of Alectra Utilities' planned investments, by Investment Category, over the 2027-2031 period.

Table 5.4.2 - 1 Summary of Capital Investments – 2027-2031

	Forecast Period (Planned)				
	2027	2028	2029	2030	2031
System Access	157.7	180.4	164.2	139.1	138.7
System Renewal	193.1	209.4	257.3	346.1	362.6
System Service	39.2	79.6	150.0	132.0	184.2
General Plant	64.8	85.5	82.6	95.9	71.8
Total Capital Expenditure ($MM)	**454.8**	**554.9**	**654.1**	**713.1**	**757.3**

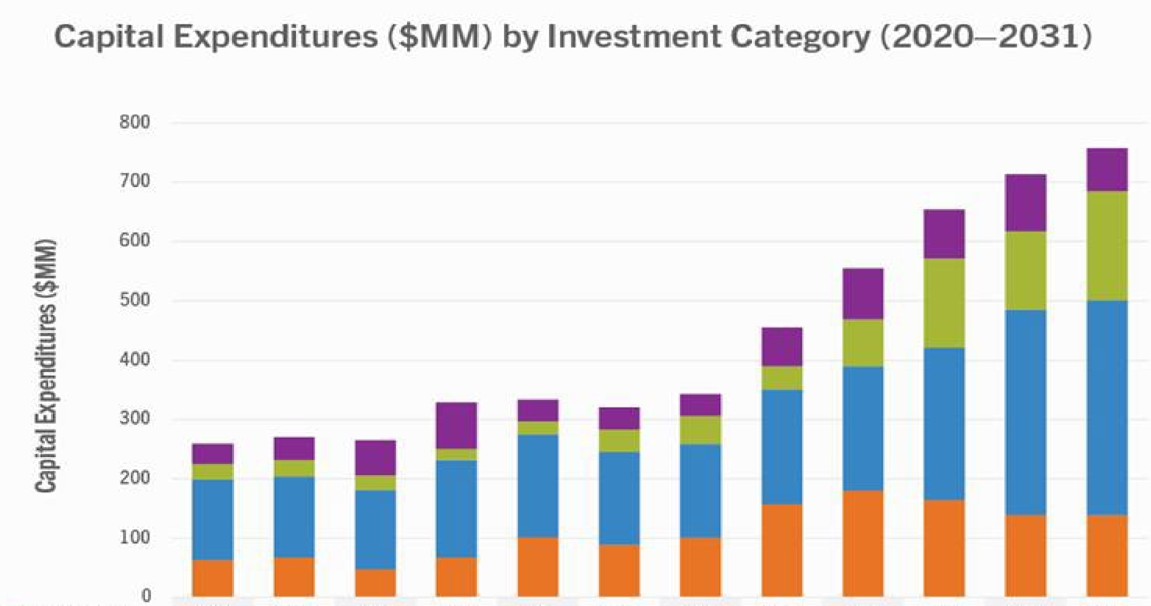
This section provides:

- A summary of planned capital expenditures across the OEB's four investment categories, along with a summary of Alectra Project Groupings (*Section 5.4.2.1.B*)
- A discussion of the key investment drivers for the OEB investment categories (*Section 5.4.2.1.C*)

Appendix B includes comprehensive investment summaries for Alectra Utilities' project groupings.

B Planned Allocation to OEB Investment Categories

Alectra Utilities is planning for year-over-year growth in the level of annual capital investments. The total planned capital expenditures are expected to increase from $454.8MM in 2027 to $757.3MM in 2031, reflecting the need to address the substantial inventory of deteriorated assets, while ensuring the system has sufficient capacity to meet the growth in electricity demand through a resilient and modern system. Figure 5.4.2 - 1 below outlines the annual capital spending from 2020 to 2031.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
General Plant	33.5	37.8	59.8	78.2	36.1	37.6	36.9	64.8	85.5	82.6	95.9	71.8
System Service	26.8	28.4	24.3	18.6	22.7	37.4	47.0	39.2	79.6	150.0	132.0	184.2
System Renewal	135.5	136.5	134.1	164.4	172.7	157.3	158.0	193.1	209.4	257.3	346.1	362.6
System Access	63.1	67.4	47.4	67.3	101.8	88.2	100.9	157.7	180.4	164.2	139.1	138.7

Figure 5.4.2 - 1 Capital Expenditures by Investment Category (2020-2031)

Over the forecast period, the DSP addresses urgent system renewal needs, with System Renewal planned investments increasing from $193.1MM in 2027 to $362.6MM in 2031. The increase is primarily driven by the need to replace deteriorated overhead and underground assets through pole remediation and cable replacement. This pace of replacement maintains a balance between ensuring reliability, resource constraints, mitigating public safety risks, and the cost of the planned work. System Service investments are planned to grow, increasing from $39.2MM in 2027 to $184.2MM in 2031, to ensure system capacity is available to meet the growing energy demands. System Access expenditures include replacement of failing first-generation metering infrastructure in addition to customer-driven expansion investments. General Plant investments are planned to increase from $64.8MM in 2027 to $71.8MM, primarily attributable to the need to settle Connection and Cost Recovery Agreements with HONI (refer to Figure 5.4.2 - 1 for indication of actual and planned capital investments from 2020 to 2031).

As described in the sections that follow (and in *Appendix B*), the needs for investment are substantial. The responding investment plan has been paced and constrained, and most importantly informed by, aligned to, and accepted by customers (through phases of customer engagement).

While needs are growing in absolute terms over the forecast period, the relative proportion of growth by category varies from one year to the next. As shown in Figure 5.4.2 - 2, investments in System Access and System Renewal are planned to represent 77% of the total capital investment plan in 2027. However, this proportion is expected to decrease to approximately 66% by 2031, as System Service investments to meet growing capacity requirements constitute a greater proportion of planned investment.

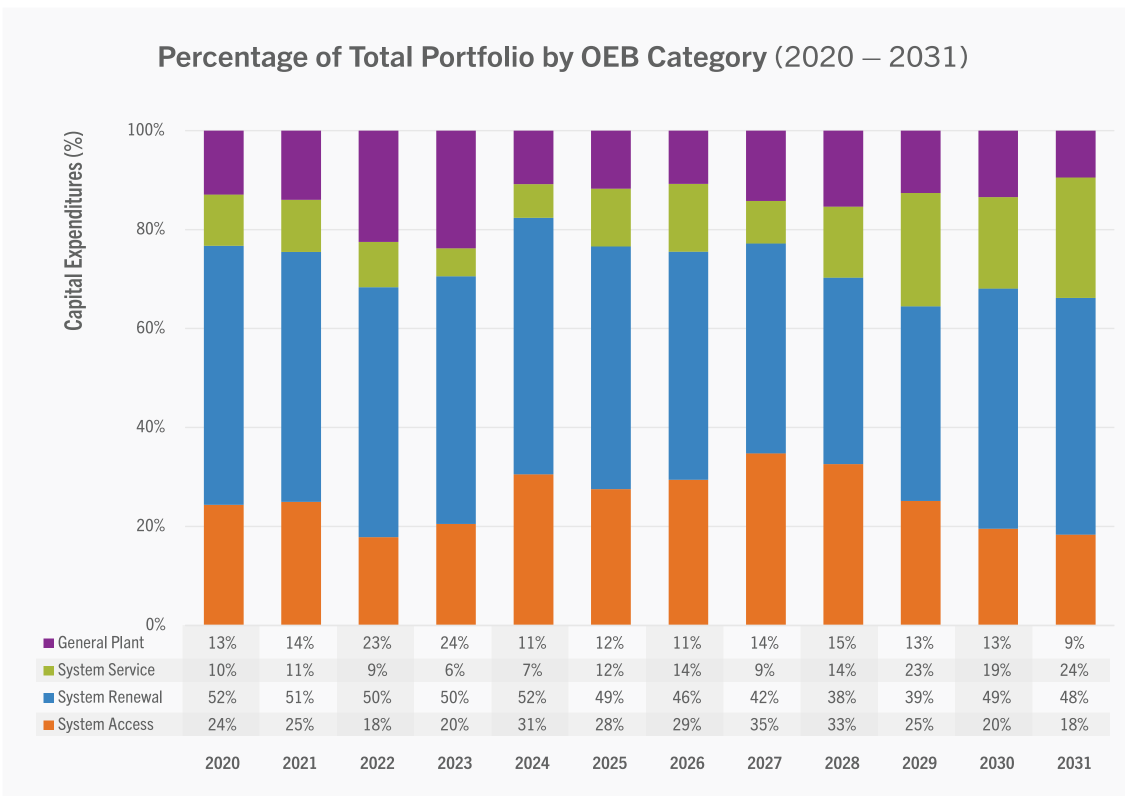


Figure 5.4.2 - 2 Percentage of Total Portfolio by OEB Category (2020 – 2031)

Figure 5.4.2 - 3 illustrates the investment proportions at five-year increments which include the 2020 historical actuals, the 2026 final bridge year and the planned 2031 investment by OEB category. From the 2026 Bridge Year, through the end of the DSP in 2031, the company expects that System Service expenditures will increase from approximately 14% of the total capital budget to approximately 24%. These investments are necessary to ensure that the distribution system can serve the growing needs of customers. At the same time, the deterioration of key overhead and underground assets requires that Alectra Utilities increase its investments in System Renewal, which continues to comprise roughly half of the company's overall planned capital investments. Finally, ongoing investments continue to be required in System Access and General Plant, connecting customers and enabling the company to operate efficiently and meet customers' service level expectations.

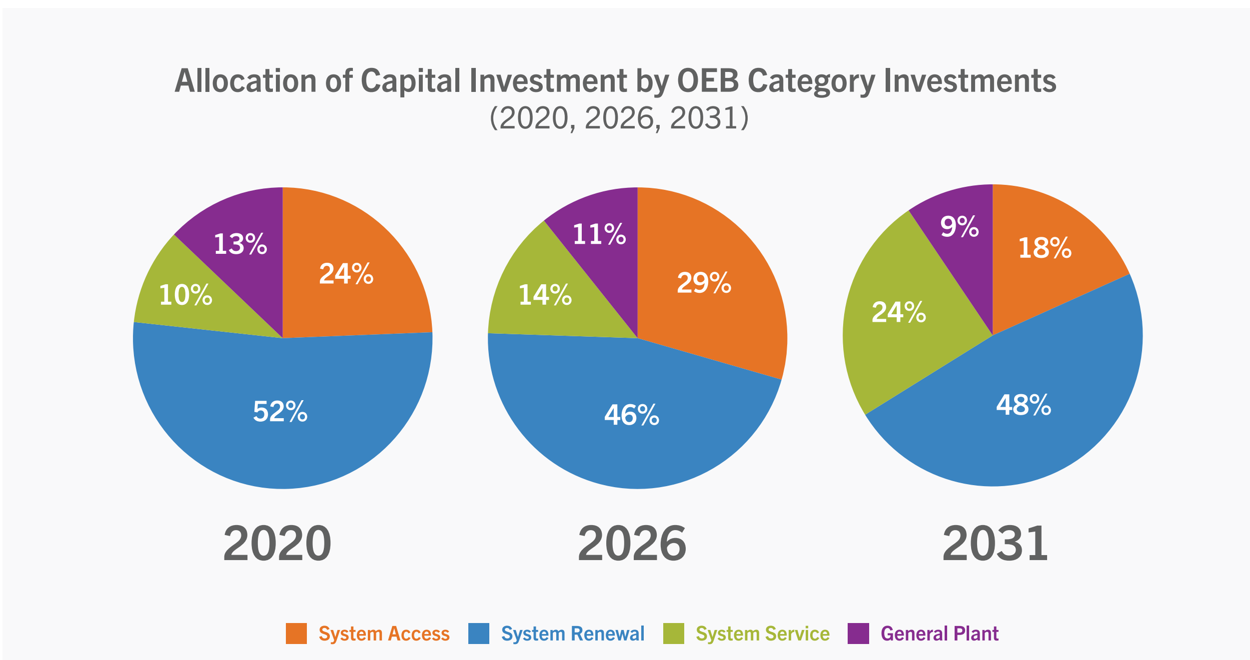


Figure 5.4.2 - 3 Allocation of Capital Investment by OEB Investment Category

B.1 System Access

System Access investments are initiated by customers or third parties (e.g. Municipalities, Regions, Ministry of Transportation, etc.) and driven by customer demand and regulatory requirements. Investments in this area include the following:

- New customer connections and subdivisions (including industrial/commercial) expansions
- Road authority and transit projects that require the relocation of distribution system assets
- Metering replacements

System Access investments can fluctuate in response to external factors such as customer-driven demand for new connections, municipal projects and regional development plans, upgrades to metering infrastructure, and requirements to accommodate road authority requests for the relocation and reconfiguration of distribution infrastructure. Investments in System Access are required to meet growing demand, comply with regulatory mandates, and support regional infrastructure development.

Over the 2027-2031 period, total investments in System Access will see growth followed by reductions due to volatility in demands from customers and agencies. System Access accounts for approximately 18% of total planned capital expenditures in 2031. Investments will continue to increase from 2027, reaching its peak in 2028 before moderating in 2030 and 2031 as some larger investments are completed. This increase will enable the company to support the growth of new customer connections based on internal and regional projections, support upcoming data centres, replace aging first-generation meters, and facilitate municipal transit and road infrastructure projects while ensuring compliance with regulatory obligations. A contribution to the slowdown in the later years is also the planned trajectory of the mass deployment of AMI 2.0 meters, which is projected to peak in 2029 and gradually decline as the project nears completion in 2032. Additionally, most of the known customer-initiated relocation and expansion projects are anticipated to finish by 2029, contributing to the slowdown in System Access investments in the latter years of the DSP plan.

The planned System Access investments for the 2027-2031 period are set out in Table 5.4.2 - 2. Further details are available in *Appendix B*.

Table 5.4.2 - 2 System Access Investments (2027-2031)

	Forecast Period (Planned)				
System Access	**2027**	**2028**	**2029**	**2030**	**2031**
Network Metering	54.1	69.9	68.6	59.8	53.0
Customer Connections	75.1	91.3	82.4	66.0	72.0
Road Authority & Transit Projects	23.5	19.2	13.2	13.3	13.7
Transmitter Related Upgrades	5.0	0.0	0.0	0.0	0.0
Total Capital Expenditure ($MM)	**157.7**	**180.4**	**164.2**	**139.1**	**138.7**

B.1.1 Network Metering (Appendix B06)

From 2027 to 2031, Alectra Utilities plans to invest $305.4MM in its Network Metering program to upgrade and maintain its wholesale revenue meters and retail revenue meters as a mandated service requirement to provide accurate and reliable measurement of electricity for settlement and customer billing. The Network Metering program consists of five activities: AMI Renewal; maintaining wholesale revenue meter compliance; maintaining retail meter compliance; completing customer requests for new and upgraded services; and replacing meters as they fail. AMI Renewal, which entails replacing Alectra Utilities' AMI 1.0 meters, is the primary driver of expenditures and makes up $247.6MM of the Network Metering expenditures in this plan period. Alectra Utilities' original AMI 1.0 meters were installed between 2006 and 2010 as required by the Minister of Energy's Smart Metering directive. These meters are now 15-19 years old, and at end-of-life with increased failure rates. Alectra Utilities began replacing its AMI 1.0 meters in 2023 as part of a ten-year exchange program that will be complete in 2032. Alectra Utilities also plans to replace 31 wholesale meter installations where the meter technology must be upgraded or where the meters are beyond their 25-year design life.

B.1.2 Customer Connections (Appendix B10)

From 2027 to 2031, Alectra Utilities plans to invest $386.8MM in Customer Connections which consists of connecting, modifying, expanding or realigning Alectra Utilities' distribution system to provide customers with electricity access and to remain in compliance with regulatory mandates. These investments cover residential and small commercial layouts, new industrial, commercial and institutional services, new subdivisions, renewable generation, customer-initiated projects and transit connections. Alectra Utilities develops future forecasts and adjusts them for changes in the electricity industry to project needs. Collaboration with developers, planners and local governments is essential to ensure timely and cost-effective service connections. Key projects focus on new residential developments and system expansions to accommodate growing electricity demand, including infrastructure and connections for electric vehicles.

B.1.3 Road Authority & Transit Projects (Appendix B11)

From 2027 to 2031, Alectra Utilities plans to invest $82.9MM on Road Authority and Transit investments which are required for modifying or relocating Alectra Utilities' distribution system, as required by road and transit authorities, to remain in compliance with regulatory mandates. Road authority investments focus on relocating or reconstructing infrastructure due to municipal and regional road works, with costs shared as per the Public Service Works on Highways Act (PSWHA). Transit investments include infrastructure relocations to accommodate new transit developments. Alectra Utilities develops future forecasts of annual unspecified projects and includes forecasts for known projects. Collaboration with road and transit authorities as well as local governments ensures timely and cost-effective project execution. All investments are required to maintain service reliability and ensure compliance with statutory and regulatory requirements, while also contributing to broader infrastructure development within Alectra Utilities' service territory.

B.1.4 Transmitter Related Upgrades (Appendix B13)

From 2027 to 2031, Alectra Utilities plans to invest $5.0MM in Transmitter Related Upgrades which will support transmission infrastructure enhancements identified through IESO Regional Planning process. Alectra Utilities is required to make a capital contribution for a Transmission Line conductor upgrade in Brampton. These investments are necessary to allow stations to be loaded to their LTR and maintain reliability of the system.

B.2 System Renewal

System Renewal investments are initiatives directed toward replacing or rehabilitating deteriorating infrastructure. Deteriorated assets require increased and more frequent operating and maintenance and lead to more prolonged outages affecting the reliable distribution of electricity. Alectra Utilities proactively replaces deteriorated and failing assets, as proactive replacement is more efficient, economical and less disruptive to customers than emergency reactive replacement after the asset fails. Proactive replacements also mitigate a broad set of risks (e.g. environmental, legal, reputational).

Over the five-year DSP planning period, annual investments focused on System Renewal will increase from $193.1MM in 2027 to $362.6MM in 2031, representing 44% of total capital expenditures over the five-year period. The increasing expenditures for System Renewal investments during the DSP period are necessary to address the growing population of poor and very poor condition assets on the distribution system. While the company has worked to maintain its assets, much of the equipment in Alectra Utilities' stations, overhead system, and underground system was first installed in the 1970s and 1980s and have now deteriorated to the extent that it must be replaced. As distribution assets age and their condition deteriorates, the pace of asset renewal must be adjusted to keep pace with the rate of deterioration. The historic rate of renewal investment is no longer sufficient to address the rate of asset deterioration.

Alectra Utilities must address the growing population of deteriorated assets if it is to maintain system reliability. Failed equipment was the leading cause of both the duration and frequency of outages. Between 2020 and 2024, failed equipment accounted for 50% of all customer hours of interruption (MED and SO excluded), more than double the amount attributed to the next most significant cause. Alectra Utilities' replacement of deteriorated and obsolete equipment, as well as investments in automation have resulted in faster fault detection and restoration, allowing the company to moderately improve reliability in the historic period. However, outages caused by underground cables and accessories remain the leading cause of failed equipment-related interruptions, contributing to 55% of the customer hours of interruption for failed equipment. Alectra Utilities expects that outage frequency and duration will increase if the growing population of deteriorated assets is not addressed.

Although Alectra Utilities has achieved improvements in reliability metrics, asset deterioration continues to challenge the sustainability of these improvements and is contributing to declining distribution system performance. Investments in underground cable replacements and injection, and overhead pole remediation to maintain system structure will be prioritized over the DSP period. These initiatives target deteriorated direct-buried cables, cable accessories, and deteriorating overhead infrastructure, which are the primary contributors to system performance declines. Additionally, increased replacements of leaking and rusting transformers identified through the Asset Condition Assessment will mitigate contamination risks. Addressing these critical assets will improve reliability, reduce the number of outages, and improve grid resilience. As referenced in *Chapter 5.2.3 Performance Measurement for Continuous Improvement*, Alectra Utilities expects that the results of the increased investments in reliability will improve SAIDI (excluding MEDs) by 20% by 2031 compared to the most recent 5-year historical average.

The planned System Renewal investments for the 2027-2031 period are set out in Table 5.4.2 - 3. Further details are available in Appendix B.

Table 5.4.2 - 3 System Renewal Investments (2027-2031)

	Forecast Period (Planned)				
System Renewal	**2027**	**2028**	**2029**	**2030**	**2031**
Overhead Asset Renewal	58.2	59.7	85.2	90.7	102.5
Reactive Capital	30.7	28.5	25.2	25.2	25.2
Rear Lot Conversion	0.0	0.0	20.3	32.7	33.6
Substation Renewal	7.5	9.6	13.1	14.7	18.7
Transformer Renewal	16.7	20.6	22.5	29.8	30.5
Underground Asset Renewal	80.0	91.0	91.0	153.0	152.1
Total Capital Expenditure ($MM)	**193.1**	**209.4**	**257.3**	**346.1**	**362.6**

B.2.1 Overhead Asset Renewal (Appendix B01)

From 2027 to 2031, Alectra Utilities plans to invest $396.3MM in Overhead Asset Renewal to address deteriorated overhead infrastructure, which will help to enhance safety and reliability. The focus for Overhead Asset Renewal is on replacing or remediating assets susceptible to failure, with specific emphasis on those at risk during adverse weather conditions as these assets present an elevated risk of failure that could affect public safety and presents added risk to utility workers. Overhead Asset Renewal encompasses investments addressing pole remediation, overhead rebuilds, voltage conversions, and switch renewals.

As part of the pole remediation projects 5,256 deteriorated poles are planned to be replaced during the 2027 to 2031 period, targeting those that are flagged as being in deteriorated condition or at risk due to being under-classed to withstand the impacts of adverse weather in certain areas. This investment will help to bolster system resilience while ensuring compliance with current standards.

Overhead rebuild projects are used to facilitate the replacement of aging conductors that have been prone to premature failure, including #6 and 4/0 copper wires. These projects aim to mitigate public safety risks from wire-down incidents and improve reliability.

Voltage conversion projects involve upgrading lower voltage distribution equipment to modern voltage levels, enhancing system resiliency by improving feeder inter-ties while also reducing maintenance costs and avoiding substation equipment replacements by decommissioning lower voltage stations.

Switch renewal investments are used to replace deteriorated and obsolete switches and enhance their capabilities by incorporating remote operation features to improve restoration times and reduce outage durations.

Overall, these investments are intended to maintain a robust distribution system by replacing deteriorated assets with those designed to modern standards, ensuring the assets can withstand increasing climate challenges that impact the overhead equipment exposed to adverse weather conditions, while meeting safety and reliability needs.

B.2.2 Reactive Capital (Appendix B05)

From 2027 and 2031, Alectra Utilities plans to spend $134.8MM in its Reactive Capital investment portfolio. The main area of focus is on unplanned and urgent work addressing assets that have failed or are at a high risk of imminent failure, or which pose a safety or environmental risk. The Reactive Capital portfolio also includes replacing equipment damaged by unexpected events (for example, due to adverse weather and damage caused by third parties) to restore power and service continuity.

Historical spending reflects the unpredictable nature of reactive capital needs. Future expenditure was developed using past trends and investments, as well as updated information regarding climate and System Renewal investment plans. The forecast indicates a gradual decrease in reactive capital expenditures, primarily due to increased System Renewal investments - although the trend is partially impacted by expectations of more frequent and intense weather events and ongoing trends in third party damage to Alectra Utilities' equipment.

The prioritization of Reactive Capital investments is driven by the need to maintain reliability and safety by replacing assets which have failed, or are at a high risk of imminent failure, or which pose a safety risk promptly and are developed using historical data and identified trends, while maintaining flexibility to re-prioritize as necessary to address urgent issues efficiently.

B.2.3 Rear Lot Conversion (Appendix B14)

From 2027 to 2031, Alectra Utilities plans to invest $86.6MM in converting rear lot infrastructure to front-lot underground systems to improve resilience to extreme weather, public safety, reliability, efficiency, and accessibility for maintenance. Rear lot conversion targets difficult-to-access overhead assets located in customers' backyards, which pose safety risks due to proximity to customer's recreational spaces, and are more prone to prolonged outages during adverse weather events because of the backyard accessibility challenges. The investment strategy involves replacing these deteriorated, substandard systems with modern underground infrastructure mitigating many of the issues attributed to rear lot construction while conforming to current best design practices. These investments are expected to deliver long-term benefits by mitigating risks to the public, ensuring enhanced reliability during extreme weather events, and enable efficiency in carrying out maintenance practices.

B.2.4 Substation Renewal (Appendix B04)

From 2027-2031, Alectra Utilities plans to invest $63.6MM in the Station Renewal Plan which focuses on replacing deteriorating assets at its Transformer Stations (TS) and Municipal Stations (MS). The plan includes investments to replace critical assets like circuit breakers and switchgear lineups to mitigate the risk of equipment failure that could lead to power outages, safety hazards, and increased costs associated with responding to equipment failures under unplanned conditions. The investments described in the plan will enhance the reliability and safety of the Alectra Utilities distribution system, in accordance with strategic objectives. The need for Station asset replacement is driven primarily by asset health indices that are based on condition assessments and supplemented by ongoing inspections and monitoring. Secondary drivers of replacement decisions include safety hazards and functional obsolescence.

B.2.5 Transformer Renewal (Appendix B03)

From 2027 to 2031, Alectra Utilities plans to invest $120.1MM towards the proactive replacement of high-risk transformers. The focus is on addressing 50% of the identified deteriorated transformers (around 4,700 units) to alleviate the risk impacting the environment and public safety. Several of the units planned for replacement present particularly challenging constraints, such as being installed in vault rooms with non-standard configurations, driving up per unit replacement costs compared to typical like-for-like replacements. Overall, these investments are necessary to ensure compliance with environmental and safety standards, and to maintain reliable service to the customers.

B.2.6 Underground Asset Renewal (Appendix B02)

From 2027 to 2031, Alectra Utilities plans to invest $567.1MM for Underground Asset Renewal. The targets of these investments are deteriorated cables, switchgear, civil structures, and urgent near-term projects. Replacement and rehabilitation of these key deteriorated asset groups will help to manage failure risks and improve reliability for customers.

The largest investment in this category is aimed at the growing population of deteriorated cables, particularly Cross-Linked Polyethylene (XLPE) cables, which are the primary contributors to outages related to underground defective equipment. The strategy to address the deteriorated cables includes both rejuvenation through cable injection on eligible cables, or full cable replacements if necessary.

Investments in replacing switchgear will target deteriorated units, with an emphasis on air-insulated and oil-insulated units that pose safety, environmental and reliability risks. Plans over the 2027 – 2031 period will address the replacement of 344 units.

Civil structure investments are intended to replace deteriorating vault lids and chamber covers to mitigate public safety risks. In some cases, full chamber replacements are required due to structural degradation of the walls.

Near-term projects will address urgent, non-discretionary underground asset issues, ensuring timely interventions to prevent extended outages or imminent risks.

The investments as planned will target deteriorated assets leading to improved system reliability, enhanced safety, and operational efficiencies while also mitigating environmental risks related to underground equipment failures.

B.3 System Service

System Service investments consist of expenditures associated with expanding the company's distribution system and addressing grid capacity, improving reliability, and ensuring safety initiatives. In addition, these investments include the expansion of SCADA and related communication infrastructure. Failure to invest in System Service upgrades would result in capacity shortages, overloading of assets, power quality issues, and an inability to support growing energy demands and both organic growth and timely new customer connection.

Over the five-year DSP planning period from 2027-2031, Alectra Utilities will prioritize investments in capacity enhancements to meet future growth requirements. This increase is primarily driven by the need to add new capacity to the distribution system to accommodate the growing energy demands from organic growth and electrification. Organic Growth, new developments including data centre expansion, and transportation are the key drivers of peak demand. As referenced in *Appendix B13 - Station Capacity,* based on municipal growth studies and provincial planning forecasts, population in Alectra Utilities' service territories is forecasted to increase 31% and households by 39% between 2021 and 2041. In addition, Alectra Utilities has received applications and customer commitments to connect additional 425MW of committed data centre load. Electric vehicle adoption by 2031 is also forecasted to result in a peak demand of 524MW. By expanding substations, upgrading distribution capacity lines, and integrating automation systems, Alectra Utilities can ensure a stable, reliable and future-ready grid capable of meeting growth demands and customer expectations.

The planned System Service investments for the 2027-2031 period are set out in Table 5.4.2 - 4. Further details are available in *Appendix B*.

Table 5.4.2 - 4 System Service Investments (2027-2031)

	Forecast Period (Planned)				
System Service	**2027**	**2028**	**2029**	**2030**	**2031**
SCADA & Automation	8.7	9.2	15.2	21.6	18.1
Capacity (Lines)	5.2	35.0	63.8	41.9	51.1
Capacity (Stations)	24.2	25.7	58.8	61.9	110.8
System Control, Communications & Performance	0.9	9.2	11.0	5.2	3.0
Safety & Security	0.0	0.2	0.9	1.1	1.1
DER Integration	0.2	0.3	0.3	0.3	0.1
Total Capital Expenditure ($MM)	**39.2**	**79.6**	**150.0**	**132.0**	**184.2**

B.3.1 SCADA & Automation (Appendix B14)

From 2027-2031, Alectra Utilities plans to invest $72.8MM to expand its SCADA and Automation capability to enhance the reliability, efficiency, and safety of its distribution system and support grid modernization objectives. Investments include deploying SCADA-enabled switches, switchgear, and reclosers; replacing existing manually operated switches with SCADA-controlled devices; and installing remotely monitored fault indicators and sensors. These investments will improve Alectra's ability to conduct rapid switching operations and load transfers, thereby reducing outage durations by restoring power more quickly to customers not in the vicinity of the problem area. In addition, these investments will improve operational efficiency by reducing the need for field crews to perform patrols and conduct manual switching operations. The deployment of additional remotely monitored devices will also provide more data from the field to System Control and back-office systems, thereby increasing the ability to analyze grid performance and asset utilization as well as respond to emerging system issues in real-time.

B.3.2 Capacity (Lines) (Appendix B12)

From 2027 to 2031, Alectra Utilities plans to invest $197.0MM in Lines Capacity investments to allow it to connect new customers and ensure reliable service to new and existing customers. The investments support new feeder builds to connect new customers, provide relief to overloaded feeders, build a primary supply for new MSs and address radial feeders. Specific projects, such as the Markham TS5 Feeder Integration and the St. Catharines Downtown Feeder Consolidation, exemplify efforts to integrate new feeders and upgrade existing ones to support growth and improve reliability. The investments are designed to increase capacity for new and existing customers, enhance operational efficiency, reduce outages, and future-proof the distribution network, supporting sustainable service growth and economic development.

B.3.3 Capacity (Stations) (Appendix B13)

From 2027 to 2031, Alectra Utilities plans to invest $281.4MM in Stations Capacity investments. These include land acquisitions for new stations, capacity upgrades at existing substations, and construction of new Alectra Utilities-owned transformer stations. Alectra Utilities' residential, commercial, industrial and institutional customer connections are increasing. Alectra Utilities has also seen a major uptake in connection requests for Data Centres and electrification in its service territory which will lead to demand increase. The current transformer stations and municipal stations that serve Alectra Utilities do not have the capacity to accommodate the load growth. Key projects include investments in transformer stations in Markham, Vaughan, Richmond Hill Brampton and Mississauga and municipal stations in Aurora, Alliston and Bradford. The investments in Stations Capacity Projects require timely execution to ensure Alectra Utilities has sufficient capacity to accommodate the load growth while maintaining a reliable source of power supply to the existing customers.

B.3.4 System Control, Communications & Performance (Appendix B14)

From 2027-2031, Alectra Utilities plans to invest $29.3MM in System Control, Communications & Performance. These investments are required to deploy communication networks, install fault indicators and sensors, and replace end-of-life Station protection and control systems. Investments will also be made to install online monitoring systems on Stations assets, as well as to address power quality issues. Deteriorating, end-of-life protection and control equipment will be replaced with modern microprocessor-based assets that provide more effective protection and control functionality as well as improved information on system events. Investments in communications infrastructure will primarily focus on the deployment of fibre-optic and WiMAX networks, to support SCADA communications and AMI 2.0 data flows. The deployment of fault indicators and sensors will provide improved fault locating capability and reduce outage response times. Online monitoring systems, such as power transformer gas and temperature monitoring and high voltage bushing partial discharge, provide valuable real-time information on asset health that can be utilized to predict potential asset failures and allow for proactive remedial action to be taken.

B.3.5 Safety & Security (Appendix B04)

From 2027-2031, Alectra Utilities plans to invest $3.3MM to address safety and security risks at its Stations. Physical security at Stations is a significant concern, and it is prudent to mitigate those risks to reduce the possibility of unauthorized access to Alectra Utilities' Stations, with consequent potential adverse impacts on reliability and safety. During the DSP period, Alectra Utilities will invest in video monitoring and other types of security systems, based on the level of based on location-specific risk and criticality. Investments are also planned to install oil-containment systems to reduce environmental risks that may result from oil leaks from power transformers. Should an oil spill occur, oil containment systems prevent the oil from contaminating soil, waterways, and parkland. Oil contamination can also be costly to rectify and the investments in oil containment systems help to avoid significant cleanup costs in the event of a spill.

B.3.6 Distributed Energy Resources (Appendix B09)

From 2027-2031, Alectra Utilities plans to invest $1.2MM in DER Supporting Technologies. This investment is primarily related to the Customer Non-Wires Solution (NWS) Design and Development project.

B.4 General Plant

General Plant investments support the daily operations of the utility, focusing on assets that are essential to business functions and generally operate outside the direct distribution system. These assets mainly include IT systems, fleet and facilities required to support both operational and administrative activities. Without these investments, Alectra Utilities would face operational inefficiencies, cybersecurity vulnerabilities, and increased costs associated with maintaining outdated infrastructure. By upgrading IT, fleet, and facility assets, the company can help ensure long-term operational sustainability and continued service excellence.

Over the five-year DSP planning period from 2027-2031, the increased volume of General Plant investments is primarily attributable to Information Technology and the need to settle Connection and Cost Recovery Agreements with HONI. Investments in Meter-to-Cash projects as part of Information Technology, which enhance billing and collections from customers, will contribute to the higher proportion of General Plant investments. Additional investments are also planned for fleet for the renewal of aging vehicles and additional vehicles to accommodate the increase in planned investments.

The planned General Plant investments for the 2027-2031 period are set out in Table 5.4.2 - 5. Further details are available in *Appendix B*.

Table 5.4.2 - 5 General Plant Investments (2027-2031)

	Forecast Period (Planned)				
General Plant	**2027**	**2028**	**2029**	**2030**	**2031**
Facilities Management	2.6	5.6	7.2	6.5	7.4
Information Technology	26.0	38.4	38.5	22.5	23.6
Fleet Renewal	24.2	23.3	18.6	17.3	14.5
Connection and Cost Recovery Agreements	10.0	16.3	16.3	47.5	24.1
Tools, Shop and Garage Equipment	2.0	1.9	2.0	2.1	2.2
Total Capital Expenditure ($MM)	**64.8**	**85.5**	**82.6**	**95.9**	**71.8**

B.4.1 Facilities Management (Appendix B07)

From 2027 to 2031, Alectra Utilities plans to invest $29.3MM in Facilities Management. These investments are required to maintain both administrative offices and operational centres. There are seven main categories which include security, HVAC, and building electrification. The purpose of the investment is to support utility operations and enhance safety and reliability within the buildings at Alectra Utilities. Key investments include replacing generators with natural gas alternatives and upgrading electrical systems to accommodate fleet electrification. Facilities Management also focuses on improvements to become more energy efficient, when assets are required to be replaced, to work towards Alectra Utilities' goal of having a net zero carbon footprint across all facilities over time. Security improvements have been planned to consolidate systems onto a unified platform, improving monitoring and response capabilities across all Alectra Utilities building locations. These investments will help to improve business continuity, safety compliance within our buildings and properties, and efficient operations of Alectra Utilities facilities.

B.4.2 Information Technology (Appendix B09 & Appendix B14)

From 2027 to 2031, Alectra Utilities plans to invest $149.0MM in upgrading its Information Technology (IT) systems to enhance operational efficiency, cybersecurity, and regulatory compliance. Major investments will go towards IT Software of $119.1MM which is essential to meet customer service expectations and to provide systems that ensure enterprise applications are efficient, reliable, and scalable with the utility's growth. Key software initiatives include investing in the following categories: $41.1MM in Grid Modernization, $25.8MM in the Meter-to-Cash system, $12.0MM in Enterprise Resource Planning, $11.1MM in Customer Service Technologies, and $15.3MM on Operational Technologies. Alectra Utilities also plans to invest $22.6MM in IT Hardware to ensure reliable performance and security; this includes investment of $10.4MM in End User Technology and $9.9MM in Data Centre Infrastructure. $7.3MM is dedicated to investment in IT Security.

B.4.3 Fleet Renewal (Appendix B08)

From 2027 to 2031, Alectra Utilities plans to invest $97.9MM in the Fleet Renewal program to maintain and modernize its fleet of vehicles and equipment to ensure fully operational and safe fleet assets to enable full, timely, and efficient service to our customers. Fleet Renewal focuses on replacing vehicles that have deteriorated in condition and are beyond their typical useful life, which ensures safety, reliability, and compliance with emissions standards for all fleet assets across Alectra Utilities. Fleet investments include heavy-duty, medium-duty, and light-duty vehicles, trailers, and fleet equipment, with a focus on enhancing operational efficiency by minimizing maintenance costs and downtime while improving vehicle safety. In addition, Fleet Renewal investments will also support Alectra Utilities' long-term goal to environmental sustainability by transitioning to electric and hybrid vehicles, which help reduce overall greenhouse gas emissions. The Fleet Renewal strategy includes an assessment of vehicle condition, age, and mileage to prioritize fleet asset replacements. Fleet Renewal also accommodates growth needs to support increasing service demands and infrastructure maintenance for Alectra Utilities Operations Teams. Overall, these investments are critical for

Alectra Utilities to continue to support operational requirements, ensuring timely service delivery, and alignment with long-term environmental goals.

B.4.4 Connection and Cost Recovery Agreements (Appendix B13)

From 2027 to 2031, Alectra Utilities plans to invest $114.2MM in Connection & Cost Recovery Agreements. Under the Transmission System Code (TSC) when a distributor engages the transmitter for capacity upgrade; it must enter into a Connection Cost Recovery Agreement (CCRA) with the transmitter. Under these CCRA investments, Alectra Utilities will be required to provide HONI with an initial capital contribution based on the difference between the total capital cost of constructing the asset and a projection of revenue earned on the conveyance of electricity through the asset. During the 2027-2031 period, Alectra Utilities will coordinate with HONI on the construction of Markham TS5 to accommodate an increase in demand in the Markham/Richmond Hill area, with completion targeted for 2028. Alectra Utilities will also collaborate with HONI to upgrade and expand the 230kV system in Brampton to support two planned stations, Heritage TS and New Goreway TS. Alectra Utilities has also planned upgrades for Newton TS in Hamilton and Campbell TS in Guelph to increase capacity resulting from residential, commercial and industrial development. Execution of these projects will ensure reliable service while adding capacity for new urban development.

C Drivers of Investments by Category

Table 5.4.2 - 6 lists the investment drivers for each investment category and provides a description of the driver in the context of Alectra Utilities' Capital Investment Plan.

Table 5.4.2 - 6 Investment Drivers by Category

Investment Category	Investment Driver	Description
System Access	Mandated Service Obligations	Compliance with all legal and regulatory requirements as well as government directives.
	Customer Service Requests	Meet Alectra Utilities' obligations to connect customers to its system.
	Functional Obsolescence	Assets are no longer aligned with present-day processes and practices such that they can no longer be maintained or utilized to support safe and reliable operations.
	Failure Risk	Address imminent risk of failure based on asset condition and deterioration. Includes risks to the environment, safety and system stability/performance.
System Renewal	Reliability	Maintain system reliability levels or improve local/feeder level reliability where performance is below average.
	Failure Risk	Address imminent risk of failure based on asset condition and deterioration. Includes risks to the environment, safety and system stability/performance.
	Functional Obsolescence	The asset is no longer aligned with present-day processes and practices such that it can no longer be maintained or utilized to support safe and reliable operations.
System Service	System Capacity	Ensure sufficient capacity to meet customer demand and contingency capacity. Operate assets within the prescribed capacity limits.
	Reliability	Maintain system reliability levels or improve local/feeder level reliability where performance is below average.
	Operational Effectiveness	Optimize the operation of assets and related processes and enhance customer experience in a financially prudent manner.

Investment Category	Investment Driver	Description
	Functional Obsolescence	Assets are no longer aligned with present-day processes and practices such that they can no longer be maintained or utilized to support safe and reliable operations.
General Plant	Operational Effectiveness	Optimize the operation of assets and related processes and enhance customer experience in a financially prudent manner.
	Functional Obsolescence	Assets are no longer aligned with present-day processes and practices such that they can no longer be maintained or utilized to support safe and reliable operations.
	System Maintenance & Capital Investment Support	Support day-to-day business operational activities. Sustain operations by providing employees with a safe working environment in an efficient and reliable manner.
	Failure Risk	Address imminent risk of failure based on asset condition and deterioration. Includes risks to the environment, safety and system stability/performance.

5.4.2.2 Investment Summaries

Alectra Utilities has provided comprehensive investment summaries for each investment group, as provided in *Appendix B* and shown in Table 5.4.2 - 7.

Table 5.4.2 - 7 List of Investment Summaries and Their Corresponding Appendix Location

Investment Narratives	Project Group	Investment Category
Appendix B01 - Overhead Asset Renewal	Overhead Asset Renewal	System Renewal
Appendix B02 - Underground Asset Renewal	Underground Asset Renewal	System Renewal
Appendix B03 - Transformer Renewal	Transformer Renewal	System Renewal
Appendix B04 - Substation Renewal	Substation Renewal	System Renewal
	Safety and Security	System Service
Appendix B05 - Reactive Capital	Reactive Capital	System Renewal
Appendix B06 - Network Metering	Network Metering	System Access
Appendix B07 - Facilities Management	Facilities Management	General Plant
Appendix B08 - Fleet Renewal	Fleet Renewal	General Plant

Appendix B09 - Information Technology Systems	Information Technology Systems	General Plant
	Distributed Energy Resources	System Service
Appendix B10 - Customer Connections	Customer Connection	System Access
Appendix B11 - Road Authority & Transit Projects	Road Authority & Transit Projects	System Access
Appendix B12 - Lines Capacity	Lines Capacity	System Service
Appendix B13 - Stations Capacity	Stations Capacity	System Service
	Connection & Cost Recovery Agreements (CCRA)	General Plant
	Transmitter Related Upgrades	System Access
Appendix B14 - Enabling Resiliency & Modernization	Information Technology Systems[94]	General Plant
	SCADA and Automation	System Service
	System Control, Communications and Performance	System Service
	Rear Lot Conversion	System Renewal

[94] Information Technology projects primarily related to Grid Resiliency and Modernization included here.

Appendix A - System Capability Assessment for Renewable Energy Generation (REG)

This section of the DSP provides information on the capability of Alectra Utilities' distribution system to accommodate Renewable Energy Generation (REG) connections. This includes an overview of the company's historical and forecast REG connection applications, both in terms of application numbers and generating capacity, the distribution system's ability to connect the anticipated projects, as well as known distribution system constraints.

A.1 Historical and Forecasted REG Connections

As of December 2024, Alectra Utilities has 6,617 REG projects connected to its distribution system, including Feed-In Tariff (FIT), microFIT, as well as commercial and residential Net Metering projects. Together, these projects provide over 179.74MW of generation capacity. Table A - 1 shows the total number and capacity of connected REG projects in Alectra Utilities service area by type as of December 31, 2024.

Table A - 1 Total Connected REG Projects (As of December 31, 2024)

Totals	Number	MW
Total Connected FIT	568	112.28
Total Connected microFIT	4,882	41.33
Total Connected Net Metering	1,167	26.12
	6,617	**179.74**

The connected FIT projects consist of 112.28MW of REG facilities that all use solar energy technologies. The connected microFIT projects (totaling 41.33MW) and net-metering projects (totaling 26.12MW) consist primarily of solar generation facilities.

A summary of the projected REG connections over 10kW is provided in Table A - 2.

Table A - 2 Forecasted Number of Renewable - Solar Applications (2025-2031)

Year	2025	2026	2027	2028	2029	2030	2031
Number of Applications (Solar)	20	21	21	22	22	23	23
Solar (MW)	4.75	4.85	4.95	5.05	5.15	5.25	5.35
Total	4.75	9.60	14.55	19.6	24.75	30.00	35.35

The forecast for 2025-2031 reflects the characteristics of renewable, specifically solar, connections in Alectra Utilities' service area. Alectra Utilities service area consists of predominantly urban regions, which are more suited to rooftop solar rather than larger ground-mounted solar or wind energy projects (which have attracted limited interest). Table A - 3 and Table A - 4 provide the cumulative numbers and installed capacity breakdown of forecasted DER facilities across Alectra Utilities' distribution system from 2025 – 2031.

Table A - 3 Forecasted DER Facilities' connections (2025 – 2031)

REG Facility	2025	2026	2027	2028	2029	2030	2031	Total
Net Metering	378	383	388	392	397	402	407	**2,747**
Energy Storage	3	3	3	3	4	4	4	**24**
Other	7	7	7	7	7	7	8	**50**
Total	**388**	**393**	**398**	**402**	**408**	**413**	**419**	**2,821**

Table A - 4 Forecasted DER Facilities' connections in MW (2025 – 2031)

REG Facility	2025	2026	2027	2028	2029	2030	2031	Total
Net Metering	6.45	6.52	6.60	6.68	6.76	6.84	6.92	**46.78**
Energy Storage	2.44	2.29	2.56	2.65	2.75	2.86	2.96	**18.51**
Other	8.28	8.36	8.45	8.53	8.62	8.70	8.79	**59.74**
Total	**17.17**	**17.17**	**17.61**	**17.87**	**18.13**	**18.40**	**18.68**	**125.03**

A.2 System Capacity for REG Connections

Each Transformer Station (TS) has short circuit and thermal limits which must be considered when connecting additional Distributed Generation (DG). Short circuit capacity is the maximum level of current a device can withstand without failure during fault conditions, such as a line-to-line or line-to-ground fault. If the fault current contribution from DG located on feeders causes total fault current to exceed equipment ratings, then that DG cannot be connected to the system until the utility undertakes corrective measures to reduce fault current and/or upgrade equipment. Thermal limit is the estimated amount of generation that can be connected to a bus before exceeding the reverse flow limits of the transformer**.**

Table A - 3 and Table A - 4 set out the remaining capacity for DG connections at Alectra Utilities' TSs and Hydro One Networks Inc.'s (HONI) TSs that supply Alectra Utilities' service territory, respectively. Remaining station capacity is calculated as the difference between TS thermal capacity and TS connected capacity. Table A - 5 and Table A - 6 provide the current remaining REG facility connection capacity for Alectra Utilities' and HONI TS that supply Alectra Utilities service territory, respectively. The stations highlighted in red do not have the ability to connect generation either due to short circuit or thermal limitations.

Table A - 5 Remaining REG facility Capacity for all Alectra Owned TSs

Connected Transformer Station	TS Thermal Capacity (kW) (Max Rating)	Total Connected DG Capacity (kW)	Estimated Available DG Capacity (kW)
VAUGHAN MTS #3[95]*	106,230	21,259	N/A
MARKHAM MTS #2[96]	42,580	9,302	N/A
VAUGHAN MTS #1	8,716	4,970	3,746
VAUGHAN MTS #1 E	107,860	5,454	102,406
VAUGHAN MTS #2	7,640	3,295	4,345
VAUGHAN MTS #4	82,500	5,015	77,485
RICHMOND HILL MTS #1	9,310	4,626	4,684
RICHMOND HILL MTS #2	38,496	2,209	36,287

[95] Note: Vaughan MTS#3 has a short circuit constraint due to the existing DER and forecasted connection of BESS project under IESO LT1 program.
[96] Note: N/A means that HONI did not allocate capacity or there is no capacity

Connected Transformer Station	TS Thermal Capacity (kW) (Max Rating)	Total Connected DG Capacity (kW)	Estimated Available DG Capacity (kW)
MARKHAM MTS #1	38,850	9,207	29,643
MARKHAM MTS #3	41,840	3,446	38,394
MARKHAM MTS #3E	43,504	12,927	30,577
MARKHAM MTS #4	94,740	1,616	93,124
JIM YARROW MTS A	28,125	3,575	24,550
JIM YARROW MTS B	28,125	4,693	23,432
ARLEN MTS	33,000	11,113	21,887
		Maximum Capacity (kW)	**490,560**

1 **Table A - 6 Remaining REG Facility Capacity for all HONI-Owned TS Supplying Alectra Utilities**

Connected Transformer Station[97]	TS Thermal Capacity (kW) (Max Rating)	HONI Allocated Capacity (kW)	Total Connected DG Capacity (kW)	Estimated Available DG Capacity (kW)
KLEINBURG TS*	46,000	N/A	0	N/A
WOODBRIDGE TS DESN 1	23,600	2,038	5,767	N/A
BRAMALEA TS DESN 3 EZ*	113,800	N/A	1,105	N/A
RICHVIEW TS DESN 3 BY*	64,200	N/A	0	N/A
WOODBRIDGE TS DESN 1 EQ*	10,300	N/A	0	N/A
LAKE TS DESN 1*	57,100	N/A	0	N/A
DUNDAS TS BY	69,600	1,000	100	N/A
GAGE TS DESN 2*	33,900	N/A	0	N/A
GAGE TS DESN 3*	30,700	N/A	0	N/A
GAGE TS DESN 4*	79,700	N/A	0	N/A
BIRMINGHAM TS DESN 2 DK*	37,200	N/A	0	N/A
CAMPBELL TS – DESN 2, ZE Bus*	15,000	4,000	4,867	N/A
EVERETT TS	63,800	2,000	3,081	60,719
HOLLAND TS	96,600	2,000	11,149	85,451
MIDHURST TS DESN1	119,400	3,500	1,791	117,609

[97] Note: * denotes short circuit

Connected Transformer Station[97]	TS Thermal Capacity (kW) (Max Rating)	HONI Allocated Capacity (kW)	Total Connected DG Capacity (kW)	Estimated Available DG Capacity (kW)
MIDHURST TS DESN2	71,500	5,000	4,645	66,855
BARRIE TS	68,500	5,000	2,904	65,596
AGINCOURT TS	59,600	1,000	200	59,400
ALLISTON TS	61,600	N/A	17	61,583
ARMITAGE TS DESN 1	119,600	4,000	2,670	116,930
ARMITAGE TS DESN 2	120,400	4,000	2,460	117,940
BUTTONVILLE TS TS Z Bus	34,000	5,000	3,865	30,135
BUTTONVILLE TS TS Q Bus	38,800	5,000	3,265	35,535
FAIRCHILD TS DESN 1 BY	36,800	2,000	359	36,441
FAIRCHILD TS DESN 2 J	27,200	N/A	93	27,107
FINCH TS DESN 1	40,700	2,000	1,960	38,740
LESLIE TS DESN 1 BY	18,400	2,000	153	18,247
LESLIE TS DESN 2 J	33,000	N/A	48	32,952
WAUBAUSHENE TS	75,900	N/A	1,543	74,357
BRAMALEA TS DESN 1 B	27,200	2,500	2,586	24,614
BRAMALEA TS DESN 1 Y	32,200	1,800	58,367	23,833
BRAMALEA TS DESN 2 JQ*	51,600	N/A	0	51,600
CARDIFF TS DESN BQ	70,100	2,000	8,142	61,958
CHURCHILL MEADOWS TS DESN BY	60,000	5,000	2,536	57,464
COOKSVILLE TS DESN 1 JQ*	57,100	N/A	29	57,071
COOKSVILLE TS DESN 2 EZ	59,200	1,000	530	58,670
ERINDALE TS DESN 1 E	25,800	5,000	49	25,751
ERINDALE TS DESN 1 Q	21,000	5,000	3,585	17,415
ERINDALE TS DESN 2 YZ	93,600	5,000	4,374	89,226
ERINDALE TS DESN 3 BJ	102,900	5,000	1,528	101,372
LORNE PARK TS DESN B	39,200	5,000	818	38,382
LORNE PARK TS DESN J	33,200	2,000	1,781	31,419
MEADOWVALE TS DESN EZ	129,200	5,000	6,647	122,553
OAKVILLE TS DESN E*	53,100	N/A	0	53,100
OAKVILLE TS DESN Z	49,400	1,000	637	48,763
RICHVIEW TS DESN 2 Q*	44,100	N/A	0	44,100

Connected Transformer Station[97]	TS Thermal Capacity (kW) (Max Rating)	HONI Allocated Capacity (kW)	Total Connected DG Capacity (kW)	Estimated Available DG Capacity (kW)
TOMKEN TS DESN 1 BY	101,200	7,000	6,912	94,288
TOMKEN TS DESN 1 EZ	102,600	5,000	167	102,433
MOWHAWK TS B1	11,700	1,000	100	11,600
MOWHAWK TS Y1	8,900	1,000	100	8,800
LAKE TS DESN 2 J1J2	7,400	2,700	1,005	6,395
LAKE TS DESN 2 Q1Q2	8,900	3,450	832	8,069
NEWTON TS*	14,200	525	0	14,200
DUNDAS TS JQ	51,800	5,000	2,150	49,650
NEBO TS DESN 1 B	41,500	1,000	175	41,325
NEBO TS DESN 1 Y	41,500	1,000	435	41,065
NEBO TS DESN 2 JQ	15,000	5,000	1,040	13,960
HORNING TS B1B2	10,600	1,000	0	10,600
HORNING TS Q1Q2	2,500	1,000	0	2,500
ELGIN TS DESN 1 DK*	8,850	N/A	0	8,850
ELGIN TS DESN 1 JQ	8,850	1,000	3,540	5,310
ELGIN TS DESN 2 EZ*	30,100	N/A	0	30,100
BEACH TS DESN 1 B1B2*	400	N/A	0	400
BEACH TS DESN 1 Y1Y2*	6,700	N/A	0	6,700
BEACH TS DESN 2 J1J2	9,200	1,000	1,450	7,750
BEACH TS DESN 2 Q1Q2	8,200	5,000	33	8,167
STIRTON TS BY	11,800	1,000	705	11,095
STIRTON TS QZ	9,000	N/A	7,086	1,914
KENILWORTH TS DESN 1*	10,600	N/A	0	10,600
KENILWORTH TS DESN 2	26,600	N/A	0	26,600
BURLINGTON TS	94,500	N/A	0	94,500
BIRMINGHAM TS DESN 1 BY	5,000	N/A	0	5,000
BIRMINGHAM TS DESN 1 JQ	5,000	550	250	4,750
BIRMINGHAM TS DESN 2 EZ	15,000	N/A	0	15,000
WINONA TS	53,300	5,000	3,905	49,395
BUNTING TS J1J2	6,300	N/A	4,000	2,300
BUNTING TS Q1Q2	6,300	1,000	358	5,942

Connected Transformer Station[97]	TS Thermal Capacity (kW) (Max Rating)	HONI Allocated Capacity (kW)	Total Connected DG Capacity (kW)	Estimated Available DG Capacity (kW)
CARLTON TS DESN 1 EQ	18,100	N/A	0	18,100
CARLTON TS DESN 2 BY	23,600	1,125	7,057	16,543
CARLTON TS DESN 2 HK	26,800	1,000	500	26,300
GLENDALE TS BJ	6,400	1,000	6,400	0
GLENDALE TS DQ	9,000	2,000	500	8,500
GLENDALE TS DESN 2 EY	10,900	N/A	6,500	4,400
VANSICKLE TS BY	23,700	1,000	7,969	15,731
VANSICKLE TS JQ	15,800	3,000	898	14,902
GOREWAY TS DESN 1 B	50,100	10,000	5,794	44,306
GOREWAY TS DESN 1 Y	51,400	10,000	4,593	46,807
GOREWAY TS DESN 2 J	25,000	5,000	3,887	21,113
GOREWAY TS DESN 2 Q	25,000	5,000	0	25,000
PLEASANT TS DESN 1 JQ	100,900	1,700	979	99,921
PLEASANT TS DESN 2 BY	37,200	10,000	4,740	32,460
PLEASANT TS DESN 2 EZ	51,700	5,000	7,487	44,213
PLEASANT TS DESN 3 F	27,700	5,000	1,303	26,397
PLEASANT TS DESN 3 V	28,600	5,000	2,169	26,431
CAMPBELL TS – DESN1, BY	61,400	5,000	26,794	34,606
CAMPBELL TS – DESN 1, JQ	63,300	5,000	16,488	46,812
CEDAR TS – DESN 1, BY	17,300	1,000	1,537	15,763
CEDAR TS – DESN 1, ZE	6,400	N/A	1,509	4,891
CEDAR TS – DESN 2, JQ	35,300	N/A	1,549	33,751
HANLON TS – BY	29,600	5,000	1,844	27,756
			Maximum Capacity (kW)	**3,286,849**

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A.3 Existing Constraints for REG Connections

As outlined in *Section A.2*, there is potential capacity to connect an additional ~3.78GW of REG facilities (491 MW on Alectra Utilities-owned TS and 3,287 MW on HONI-owned TS) to Alectra Utilities' distribution system. Despite the available potential capacity, REG facilities are currently unable to connect to specific areas within Alectra Utilities distribution system due to constraints at either the transmission or distribution level.

The following constraints can limit the number of and/or curtail the output of new REG facilities:

1. Hosting Capacity: Verifies that additional Distributed Energy Resources (DER) can be accommodated without violating voltage-quality limits or compromising feeder loading margins. Exceeding hosting capacity can lead to unacceptable voltage fluctuations, equipment damage, or the inability to connect new REG facilities to the grid.

2. Asset Thermal Integrity: Confirms that projected current levels remain within the temperature ratings of conductors, transformers, and protective devices. If not addressed, assets may overheat and degrade prematurely, leading to equipment failures, costly replacements, or extended service interruptions.

3. Reverse Power Flow: Assesses the risk of sustained back-feed toward the substation, ensuring voltage-regulating equipment and protection schemes (originally configured for one-way flow) continue to operate correctly under export conditions. If left unmitigated, reverse flows can cause mis-operation of protection systems, unstable voltage regulation, and heightened safety risks for both utility workers and customers.

4. Short-Circuit Contribution: Calculates incremental fault current from new DERs to keep total fault levels below equipment interrupting ratings and to maintain selective coordination across fuses, reclosers, and circuit breakers. If unmanaged, excessive fault current may exceed equipment capabilities, cause protection devices to fail, or trigger widespread outages due to loss of coordination.

Based on the number of REG facilities forecasted for the 2025 – 2031 period, Alectra Utilities expects some locations within the distribution system may be subject to the constraints mentioned above. Specifically, Table A - 7 identifies the Alectra Utilities and HONI stations that currently have constraints limiting the connection of REG facilities.

Table A - 7 Existing Connection Constraints breakdown for Alectra Utilities and HONI TS

Transformer Station Owner	Capacity and/or Short Circuit Constraints
Alectra Utilities	• VAUGHAN MTS #3 • MARKHAM MTS#2
HONI	• ALLISTON TS • FAIRCHILD TS DESN 2 J • WOODBRIDGE TS DESN 1 • WOODBRIDGE TS DESN 1 EQ • DUNDAS TS BY • ELGIN TS DESN 1 DK • GAGE TS DESN 2 • GAGE TS DESN 3 • GAGE TS DESN 4 • BEACH TS DESN 1 B1B2 • BEACH TS DESN 1 Y1Y2 • KENILWORTH TS DESN 1 • KENILWORTH TS DESN 2 • BURLINGTON TS • BIRMINGHAM TS DESN 1 BY • BIRMINGHAM TS DESN 2 DK • BIRMINGHAM TS DESN 2 EZ • BUNTING TS J1J2 • CARLTON TS DESN 1 EQ • CEDAR TS – DESN 1, ZE • CEDAR TS – DESN 2, JQ • GLENDALE TS DESN 2 EY • KLEINBURG TS • LAKE TS DESN 1 • RICHVIEW TS DESN 3 BY • RICHVIEW TS DESN 2 Q • OAKVILLE TS DESN E • COOKSVILLE TS DESN 1 JQ • BRAMLEA TS DESN 2 JQ • BRAMLEA TS DESN 3 EZ • NEWTON TS • ELGIN TS DESN 2 EZ

To date, Alectra Utilities has not encountered consistent, systematic feeder-level constraints preventing the connection of REG facilities. However, potential constraints during the 2025 – 2031 period include:

1. Insufficient individual pad-mount or pole-mount transformer and secondary conductor capacity
2. Thermal violations for individual pad-mount or pole-mount transformers and secondary conductors
3. Increased customer-side voltage due to the number of REG facilities

These potential feeder constraints, coupled with the previously mentioned TS-level constraints, can impact the interconnection of the forecasted number of REG facilities over the 2025 – 2031 period.

A.4 REG Investments Summary

Alectra Utilities proposes to undertake several connection asset, expansion and other modernization investments which will further facilitate REG connections within its service area.

A.4.1 Grid Modernization

Alectra Utilities is implementing several initiatives to modernize its grid and enable the integration of REG, driven by regulatory mandates, market demands, and Ontario's energy transition policies. Specifically, the following programs have been developed to ensure Alectra Utilities remains compliant with the external initiated drivers. These programs include:

i. The Advanced Distribution Management System (ADMS) integrates SCADA, DMS, and OMS to enhance grid control, automation, and real-time data monitoring, ensuring the efficient operation of renewable energy sources.

ii. The DER Wholesale Market Preparedness program ensures compliance with the IESO's Market Renewal Program and OEB directives, enabling real-time DER coordination, NWS implementation, and market participation.

iii. The Integrated Network Management (INM) platform centralizes and harmonizes data, improving grid planning and operational efficiency essential for Distributed Energy Resources (DERs) integration.

iv. The Planning Tools and Automation initiative streamlines system analysis and supports compliance with the updated Distribution System Code, Non-Wires Solutions (NWS) guidelines, and the Benefit-Cost Analysis (BCA) Handbook, which are critical for adopting renewable energy and evaluating alternative grid solutions.

For more information on each of these programs, refer to *Section IV* in *Appendix B14 - Enabling Resiliency & Modernization*.

A.4.2 SCADA and Automation

The SCADA & Automation program involves the deployment of SCADA-enabled switches, reclosers, Trip Savers, fault indicators and a supporting communications backbone tied into SCADA system. These devices give operators real-time visibility and automated Fault Detection, Isolation and Restoration (FDIR), allowing feeders to be reconfigured and loads balanced within seconds, which sharply reduces outage duration and truck rolls. As it related to REG facilities, the enhanced telemetry delivers real-time visibility into grid conditions, allowing Alectra Utilities to coordinate more effectively with localized REG facilities, keep them online during abnormal events, and use their output to relieve the extra load on an adjacent circuit after a FDIR operation.

For more information, refer to *Section II* in *Appendix B14 - Enabling Resiliency & Modernization.*

A.4.3 System Control, Communication & Performance

The System Control, Communications & Performance program modernizes Alectra Utilities' monitoring, protection, and communications backbone from the substation to the feeder edge. The program deploys online transformer health sensors, microprocessor relays, fault indicators, and redundant WiMAX/fibre links that stream high-resolution operating data to the SCADA system. These upgrades give system operators real-time visibility into loading, voltage, power factor, and fault status, while providing the communication mediums to enable remote switching and automated FLISR schemes. The same capabilities directly enable the integration, monitoring, and co-ordination of REG facilities, as a strengthened communications backbone will integrate REG facilities into the SCADA system, providing live statistics so system operators can assess their impact, during normal operations and whether those resources can remain online instead of being automatically curtailed during abnormal system conditions. Concurrently, advanced microprocessor relays refine protection and coordination with these facilities, keeping both the distribution network and the connected renewables operating safely within their prescribed limits.

For more information, refer to *Section II in Appendix B14 - Enabling Resiliency & Modernization*.

A.4.4 Substation Renewal

The Substation Renewal program tackles the mounting failure risk posed by aging transformers, switchgear, circuit breakers, and protection systems across 14 Transformer Stations and 149 Municipal Substations. The program will replace or refurbish deteriorated switchgear line-ups, install arc-flash-resistant vacuum breakers, modernize protection with microprocessor relays, recondition transformer tanks and radiators, and add oil-containment and security systems asset-health assessments and customer reliability needs. These upgrades reduce the probability of catastrophic equipment failures, shorten outage durations, and cut maintenance costs while bringing the stations up to current safety and environmental standards. Crucially, the new relays, event recorders, and SCADA-ready switchgear feed granular, real-time data to the SCADA System, letting system controllers see feeder and transformer headroom and issue remote switching commands in seconds. With faster fault clearing, bidirectional protection settings, and greater load-transfer flexibility, substations can now accommodate the additional fault current, voltage swings, and reverse-power flow from various REG facilities. The program preserves reliability for up to 10,000 customers per station but also unlocks new hosting capacity for new REG facilities.

For more information, refer to *Appendix B04 - Substation Renewal*.