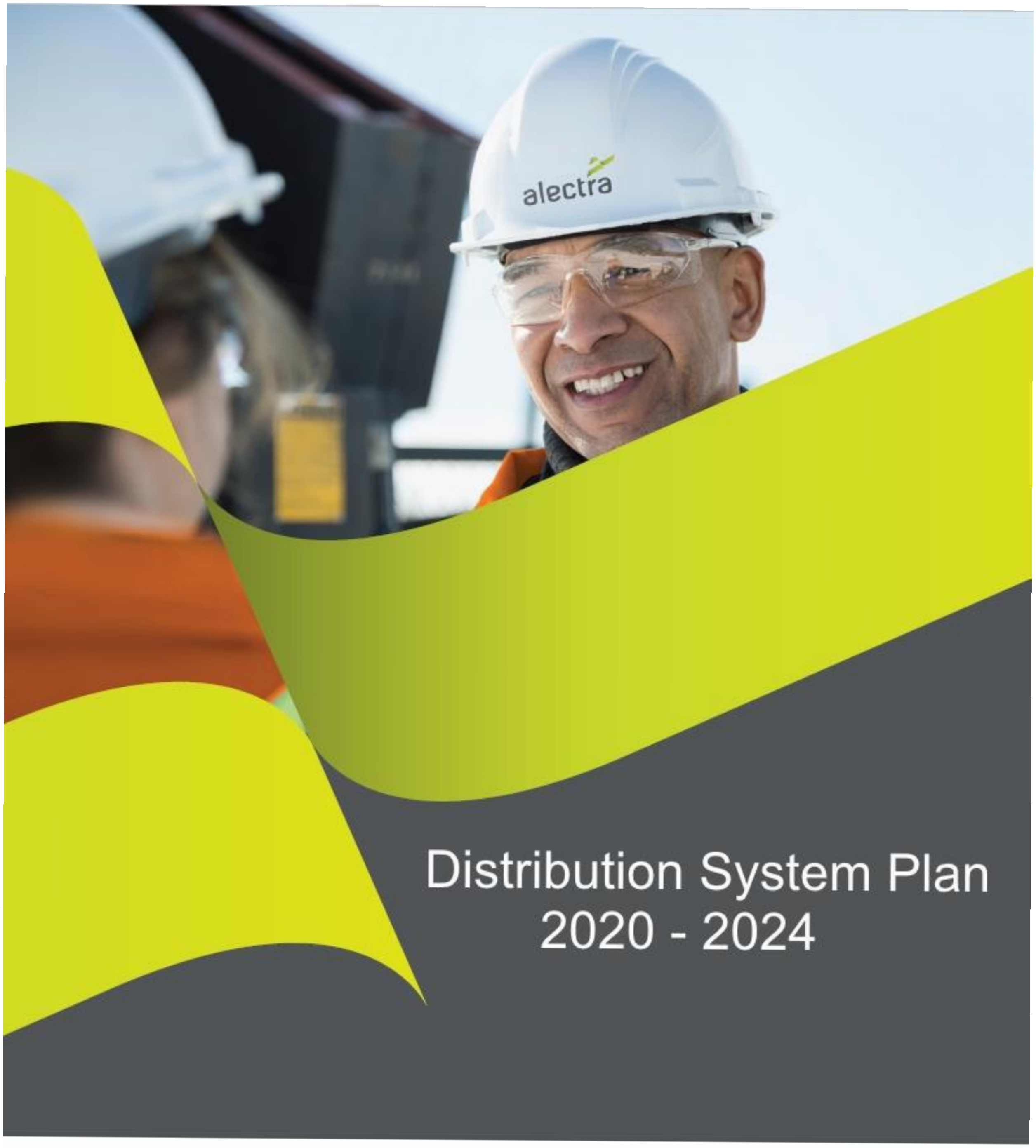
Exhibit 4, Tab 1, Schedule 1

Alectra Utilities 2020-24 Distribution System Plan



Distribution System Plan 2020 - 2024

alectra utilities

May 2019

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Glossary

Acronym	Meaning
ABB	ABB Group
ACA	Asset Condition Assessment
ADMS	Advanced Distribution Management System
AFR	Automatic Feeder Restoration
AI	Artificial Intelligence
AM	Asset Management
AMI	Advanced Metering Infrastructure
ANSI	American National Standards Institute
AODA	Accessibility for Ontarians with Disabilities Act
AVL	Automatic Vehicle Location
BAS	Building Automation System
BPCA	Baseline Property Condition Assessment
BRT	Bus Rapid Transit
BUR	Built-Up Roof
C55	Copperleaf C55
CAE	Critical Alarm Enunciator
CAPEX	Capital Expenditure
CC&B	Customer Care and Billing
CCRA	Connection and Cost Recovery Agreements
CDM	Conservation and Demand Management
CGS	Customer Generating Station
CHI	Customer Hours of Interruption
CI	Configuration Item
CI	Customers Interrupted
CIMA	Chartered Institute of Management Accountants
CIR	Capital Investment Register
CIS	Customer Information System
CMI	Customer Minutes of Interruption
CMMS	Computerized Maintenance Management System
CN or CNR	Canadian National (Railway)
COI	Configuration Object Invetory
CPI	Cost Performance Index
CSA	Canadian Standards Associations
CTM	Cable Transition Modules
CTS	Customer Transformer Station
CYME	Network Simulation Engines
DA	Distribution Automation
DER	Distributed Energy Resources
DERMS	Distributed Energy Resource Management System
DESN	Dual Element Spot Network
DG	Distributed Generation
DGA	Dissolved Gas Analysis

Acronym	Meaning
DNP	Distributed Network Protocol
DS	Distributon Station
DSC	Distribution System Code
DSP	Distribution System Plan
EA	Environmental Assessment
EDR	Electricity Distribution Rates
EDS	Electricity Distributor Scorecard
EOL	End-of-Life
EPC	Engineering Procurement Construction
EPR	Ethylene Propylene Rubber-insulated
ERM	Enterprise Risk Management
ERP	Enterprise Resource Planning
ESA	Electrical Safety Authority
EUSA	Electrical Utilities Safety Association of Ontario
EV	Electric Vehicle
F	Fair (With respect to Health Index)
FAIDI	Feeder Average Interruption Duration Index
FAIFI	Feeder Average Interruption Frequency Index
FCA	Facility Condition Assessment
FDIR	Fault Detection, Isolation and Restoration
FIT	Feed-in-Tariff
FOSC	Fiber Optic Splice Closure
G	Good (With respect to Health Index)
GATR	Guelph Area Transmission Reinforcement
GE	General Electric
GGH	Greater Golden Horseshoe
GHG	Greenhouse Gas
GIS	Geographical Information System
GMS	Garage Management System
GOOSE	Generic Object Oriented Substation Event
GP	General Plant
GPS	Global Positioning System
GS	Generating Station
GTA	Greater Toronto Area
GTHA	Greater Toronto and Hamilton Area
GW	Gigawatt
HaLRT	Hamilton Light Rail Transit
HEMS	Home Energy System
HI	Health Index
HOEP	Hourly Ontario Energy Price
HONI	Hydro One Networks Inc.
HPGE	high-purity germanium
HuLRT	Hurontario Light Rail Transit
HV	High Voltage

Acronym	Meaning
HVAC	Heating, ventilation, and air conditioning
HWY	Highway
ICI	Industrial, Commercial & Institutional
ICM	Incremental Capital Module
IEEE	Institute of Electrical and Electronic Engineers
IESO	The Independent Electricity System Operator
iPass	Integrated Planning and Scheduling
IR	Infrared
IRRP	Integrated Regional Resource Plan
IT	Information Technology
IT/OT	information technology and operational technologies
IVR	Interactive Voice Recognition
JDE	JD Edwards
KPI	Key Performance Indicator
kV	kilovolt
KWCG	Kitchener, Waterloo, Cambridge, Guelph
LAC	Local Advisory Committee
LAN	Local Area Network
LAP	Local Achievable Potential
LBD	Load Break Device
LDC	Local Distribution Company
LIS	Load Interrupting Switches
LOS	Loss of Supply
LPSS	Load Profiling and Settlement System
LRT	Light Rail Transit
LTEP	Long-Term Energy Plan
LTR	Limited Time Rating
MAADs	Mergers, Acquisitions, Amalgamations and Divestitures
mCHP	micro-combined heat and power
MDM/R	Meter Data Management and Repository
MED	Major Event Day
MEP	Municipal Energy Plan
MIST	Metering Inside the Settlement Timeframe
MS	Municipal Substation
MSP	Metering Service Provider
MTO	Ministry of Transportation of Ontario
MTS	Municipal Transformer Station
MUL	Maximum Useful Life
MVA	Mega Volt Amp
MW	Megawatt
NA	Needs Assessment
NAC	Network Access Control
NON TR	Non Tree Retardant
O&M	Operating and Maintenance

Acronym	Meaning
OBC	Ontario Building Code
OEB	Ontario Energy Board
OH (or O/H)	Overhead
OM&A	Operating, Maintenance and Administration
OMS	Outage Management System
ONAF	Oil Natural Air Forced
ONAN	Oil Natural Air Natural
ORTAC	Ontario Resource and Transmission Assessment Criteria
OTC	Offer to Connect
P	Poor (With respect to Health Index)
P&C	Protection and Control
P6	Primavera
PCB	Polychlorinated Biphenyl
PDG	Program Delivery Group
PILC	Paper Insulated Lead Covered
PME	Primary Metering Enclosures
PPE	Personal Protection Equipment
PSWHA	Public Service Works on Highways Act
PUC	Power Utility Corporation
PUL	Projected Useful Life
PV	Present Value
PV	photovoltaic
QEW	Queen Elizabeth Way
RCM	Reliability Centered Maintenance
REG	Renewable Energy Generation
RER	Regional Express Rail
RFC	Request for Change
RFP	Request for Proposal
RGEN	Renewable Generation
RIP	Regional Infrastructure Plan
RNI	Regional Network Interface
RRF	Renewed Regulatory Framework
RRFE	Renewed Regulatory Framework for Electricity
RTU	Remote Terminal Unit
S4T4	Schedule 4 Type 4
SA	Scoping Assessment
SA	System Access
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SDR	Station Drawing Depository
SF6	Sulfur Hexafluoride
SME	Subject Matter Expert
SONET	Synchronous Optical Networking

Acronym	Meaning
SOR	Statutory Orders and Regulations
SPI	Schedule Performance Index
SR	System Renewal
SS	System Service
SUE	Subsurface Utility Engineering
SWI	Systems With Intelligence
TCE	TransCanada Energy
TCIP	Transmission Control Internet Protocol
TDR	Time Domain Reflectometer
TR-DB	Tree Retardant Direct Buried
TR-ID	Tree Retardant or Strand Blocked In-Duct
TR-XLPE	Tree Retardant Cross-linked polyethylene
TS	Transformer Station
TSC	Transmission System code
TSSA	Technical Standards and Safety Authority
TTC	Toronto Transit Commission
TUL	Typical Useful Asset Life
TV	Television
UG (or U/G)	Underground
ULA	Unlimited License Agreement
VG	Very Good (With respect to Health Index)
VMC	Vaughan Metropolitan Centre
VP	Very Poor (With respect to Health Index)
VPP	Virtual Power Plant
WFM	Workforce Management (System)
XLPE	Cross-linked Polyethylene
YEC	York Energy Centre
YRRT	York Region Rapid Transit
YRRTC	York Region Rapid Transit Corporation
YRT	York Region Transit

5.0 INTRODUCTION

This is the first 5-year Distribution System Plan ("DSP") that has been prepared by Alectra Utilities Corporation ("Alectra Utilities") on an integrated basis for its entire service territory. Alectra Utilities was formed on February 1, 2017 through the consolidation of PowerStream Inc., Enersource Hydro Mississauga and Horizon Utilities Corporation and subsequent acquisition of Brampton Hydro Inc. In addition, on January 1, 2019, Guelph Hydro Electric Systems Inc. was consolidated into Alectra Utilities. Although Alectra Utilities' capital investment plans and electricity distribution rates have, to date, been established on an individual basis for each of its five rate zones, corresponding to each of the predecessor utility service territories, to support the effective and efficient planning of capital investments and its efforts to operate as a single entity, Alectra Utilities has developed this DSP for its system as a whole.

This DSP establishes Alectra Utilities' capital investment plans for its distribution system over the 2020 to 2024 planning period. Alectra Utilities has prepared this DSP in accordance with the Ontario Energy Board's ("OEB" or the "Board") July 12, 2018 *Filing Requirements for Electricity Distribution Rate Applications – 2018 Edition for 2019 Rate Applications – Chapter 5, Consolidated Distribution System Plan"* (the "DSP Filing Requirements"). Consistent with the DSP Filing Requirements, this DSP provides a consolidated set of documentation concerning Alectra Utilities' Asset Management Process and Capital Investment Plan for its distribution system, using a standardized approach and structure. It is supported by information about the company's efforts to: identify and take into consideration the needs, priorities, and preferences of its customers; to coordinate planning with third parties; as well as to measure its performance with a view to achieving continuous improvement.

The development of this DSP is responsive to the OEB's Decision and Order in EB-2016-0025 (the "MAADs Application") and the utility's subsequent annual electricity distribution rates ("EDR") applications. In the MAADs Application, Alectra Utilities indicated that it would file a consolidated five-year DSP in 2019. This was accepted by the OEB in the Decision and Order. Further, in its Decision and Order on Alectra Utilities' 2018 EDR Application (EB-2017-0024), the OEB reconfirmed the importance of a consolidated DSP, and the relationship between capital planning and funding. The OEB stated that it *"requires Alectra Utilities to file a consolidated DSP as a filing requirement with any [Incremental Capital Module] ICM application requesting rate changes for 2020 rates and beyond"* (EB-2017-0024, Decision and Order, April 6, 2018, p. 2).

The development of the DSP was informed by: Corporate Strategic Goals and Objectives; customer input; an Asset Management Framework; and the OEB's policy framework. The Asset Management Framework sets the foundation for the DSP and all planned capital investments through five guiding principles: Customer, Financial, Operational, Regulatory, and Organizational. Stemming from the Asset Management Framework is the Asset Management process, which is informed by an assessment of customer needs and priorities identified through an initial phase of customer engagement before investment planning began. These processes are summarized in section 5.2.1 of the DSP.

Alectra Utilities' DSP is designed to provide value for money and was developed to address and appropriately balance: the needs and preferences of its customers; its distribution system requirements; and relevant public policy objectives. Based on identified investment needs, Alectra Utilities developed and evaluated solutions through a consistent and uniform process based on a Value Framework that assesses the value of an investment (from a customer and organization perspective) and risk mitigation. Alectra Utilities' uniform approach to evaluating investment solutions ensured that all capital investment needs were assessed on a common scale (i.e. using a present value approach). Leveraging a leading practice multi-variate optimization software platform, CopperLeaf C55, Alectra Utilities developed an optimized investment portfolio of investments and presented investment options with costs and trade-offs to customers in a second phase of customer engagement. When presented with investment options, Alectra Utilities customers indicated preference to fund the level of investment recommended by Alectra Utilities.

In order to objectively confirm that the methodologies and approaches taken by Alectra Utilities in preparing the DSP are reasonable and appropriate, it engaged Kinectrics Inc. and Vanry and Associates as third-party experts to provide independent reviews of the Asset Condition Assessment and the overall plan, respectively.

The result of this significant effort is a DSP that demonstrates how Alectra Utilities has aligned the outcomes of its capital investment planning process with the OEB's expected outcomes[1] and the priority needs of the utility's distribution system and customers. The investments in the DSP reflect the priority needs of Alectra Utilities' distribution system and its customers as follows:

[1] Specifically, the performance outcomes identified in the OEB's *Handbook for Utility Rate Applications*: Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance.

(i) Increase the level of investment in its deteriorating underground systems.

Alectra Utilities has experienced declining levels of reliability, both in terms of frequency and duration of outages, as illustrated by trends that identify increasingly unacceptable customer service outcomes in the absence of remediate investment. The leading cause of this trend is defective equipment, in particular, failures of underground direct-buried cable and cable accessories.

A recent specific example underlying these trends is the York Hill/Hilda neighbourhood in Vaughan, which was scheduled for underground cable replacement in 2019 however from June 22 to July 13, 2018, approximately 250 customers starting experiencing an outage approximately once every three days during this period. Cables which Alectra Utilities repaired would fail again within a short duration. Alectra Utilities was ultimately forced to replace the cable in the area on an emergency basis at a higher cost and with greater disruption, causing further impacts to the affected customers. Figure 5.0 - 1 illustrates the deteriorated and damaged underground direct buried cables in the York Hill/Hilda neighbourhood. In order to mitigate such reliability and customer impacts caused by its deteriorating underground systems, a key focus for this DSP is the renewal of the company’s underground assets. Alectra Utilities has experienced an increasing number of areas with deteriorating underground cables similar to issues experienced in the York Hill/Hilda neighbourhood. Figure 5.0 - 2 and Figure 5.0 - 3 illustrate underground systems in neighbourhoods at Rathburn/ Creditview, as well as Bough Beeches/ Claypine which have experienced a high number of recent underground cable failures, which require urgent replacement. Total underground asset investment in the DSP represents approximately 28% of the required capital expenditure over the 2020-2024 planning period.

Figure 5.0 - 1: Direct Buried Cables at York Hill/Hilda in Vaughan

Figure 5.0 - 2: Rathburn Area 2019-2020 Cable Replacement Project

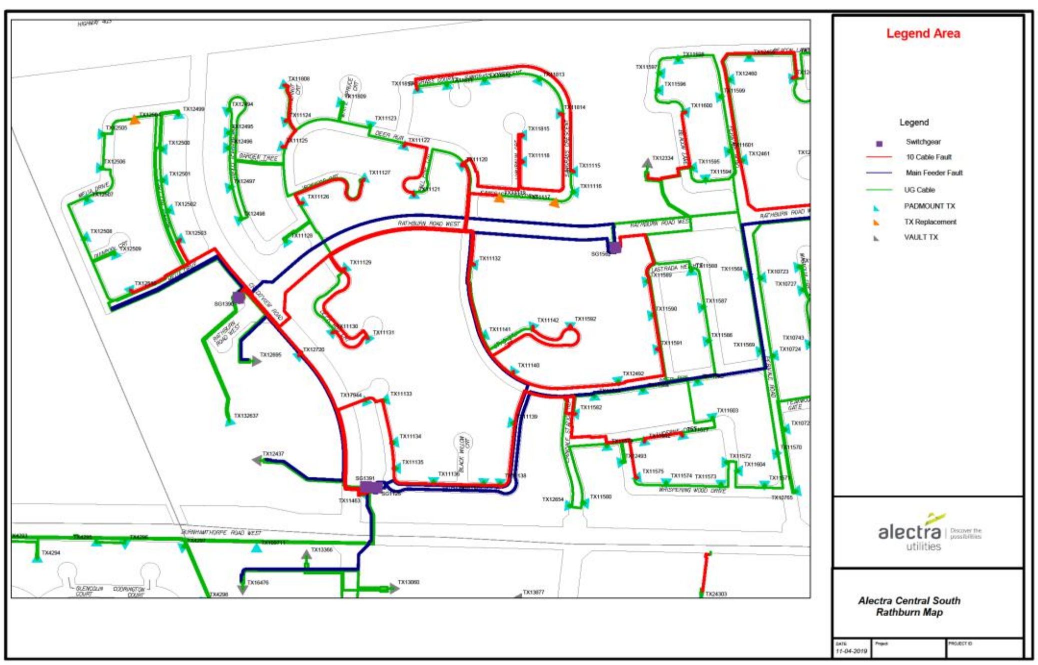
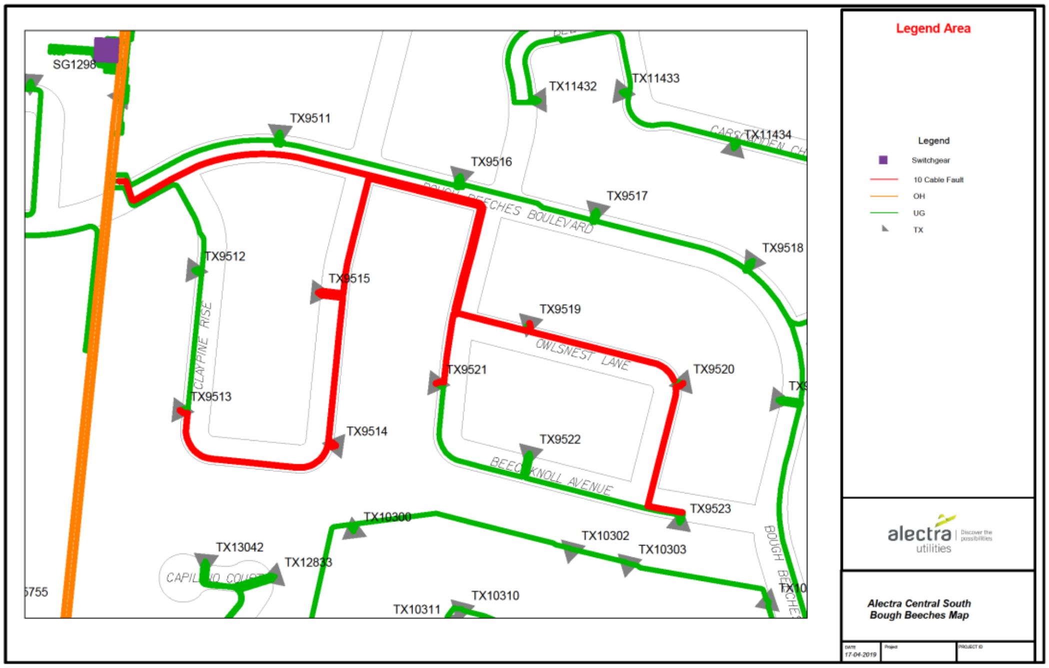


Figure 5.0 - 3: Bough Beeches Area 2020 Cable Replacement Project

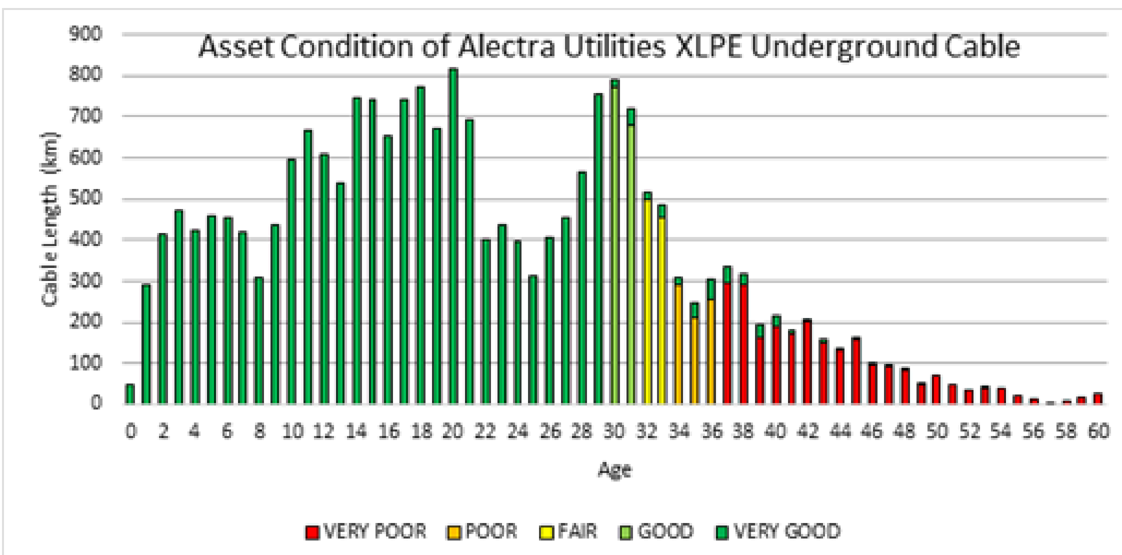


While in the York Hill/Hilda example Alectra Utilities was fortunate to be able to work within its capital investment portfolio to substitute and defer other capital work to accommodate this emergency cable replacement, this is not a sustainable solution for Alectra Utilities going forward. Alectra Utilities is facing a large capital asset bubble specifically with underground cables that are now coming due. These cables were installed during a period in time when Alectra's municipalities experienced significant growth (1960s to 1980s). The required replacement of these underground cables, now 40 to 60 years old, is far and above anything that would have been contemplated in Alectra Utilities' base rates. This issue is further exasperated by an even larger looming demand coming from installed cables between 1980 to 1990 that are starting to reach end of life and it is absolutely imperative that Alectra Utilities secure funding and get under control this renewal investment and address the large inventory of end of life cable that must be replaced now before Alectra Utilities needs to deal with the even larger population of cables installed 30 to 40 years comes due.

Alectra Utilities has been accelerating the underground cable replacement where possible, has introduced cable injection to slow down the rate of deterioration of cables and has spent considerable time and effort to understand, document and track cable condition. Despite all of this Alectra Utilities' efforts are being overwhelmed. Reliability is worsening. That is a fact. More work is being carried out on an emergency basis because to continue on, as is, in certain cases would be unbearable to customers. That is a fact. Customers are not receiving the service that they expect and are willing to pay for. That is also a fact.

Figure 5.0 - 4 illustrates the condition demographic distribution of installed cables in Alectra's service territory and the condition assessment of these assets. Notice that the majority of cables contributing to the worsening of reliability experienced by customers involve cables installed in the outer far right years in the graph, identified in the red and orange bars indicating very poor or poor condition. When considering the size of this population and the effect it has had on reliability and the looming population of deteriorating and aging cables still to come denoted by the green bars, it is clear that a significant cable renewal investment is required.

Figure 5.0 - 4: Asset Condition of Alectra Utilities XLPE Underground Cable



(ii) Enhance the resilience of its overhead system to adverse weather events.

In order to address public and worker safety concerns, as well as reliability needs, a key focus for investment is on replacing and remediating overhead assets that are deteriorated or otherwise prone to failure from adverse weather conditions. A particular area of focus will be on renewing, through reinforcement or replacement, deteriorated poles that have been assessed as being in Poor or Very Poor condition based on the 2018 Asset Condition Assessment[2]. Reinforced and replacement poles are more resilient to ice and wind loading. Alectra Utilities will specifically target a particular population of wood poles in circumstances where they are carrying four circuits. This is a scenario that has been found to be particularly susceptible to failure during storm and high wind events, as shown in Figure 5.0 - 5.

Figure 5.0 - 5: High winds caused downed power lines on Bayview Avenue in 2018

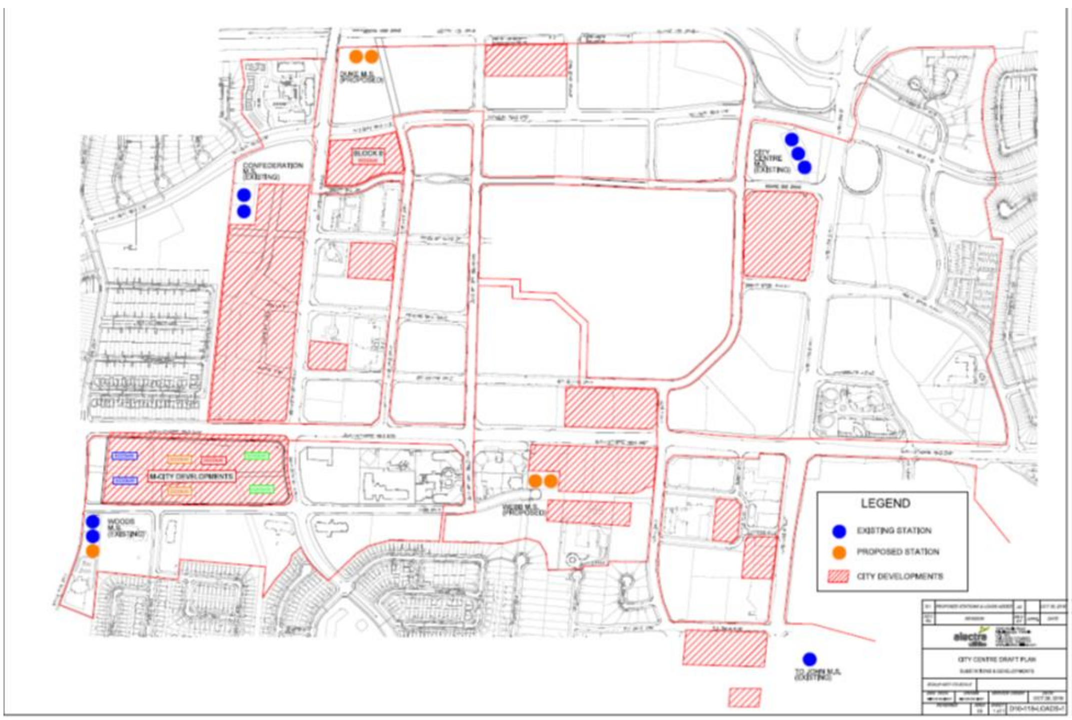
(iii) Be responsive to anticipated needs in areas of new greenfield development and urban redevelopment/intensification.

In order to fulfill its obligations as a licensed distributor, Alectra Utilities must ensure that its system has sufficient capacity to connect new customers based on forecasted needs and to alleviate capacity constraints. Alectra Utilities' investment needs in this respect are primarily driven by: the pace and extent of urban development into greenfield areas; the intensification and redevelopment of downtown areas; and the need to address specific locations where inadequate backup capacity is available due to the configuration of existing supply lines.

[2] Appendix D - Asset Condition Assessment – 2018

Key areas of greenfield expansion include: the Markham Future Urban Areas; West Vaughan; Northwest Brampton; and Stoney Creek, in Hamilton. Key areas of intensification and redevelopment include: downtown Mississauga; the Lakeshore Area of Mississauga; Brampton City Centre; Vaughan Metropolitan Centre; and several areas in Hamilton. In downtown Mississauga, for example, Alectra Utilities has been notified of planned developments that include 6 buildings, each approximately 40 storeys tall, along with planned office towers and related developments, all within the same area, requiring incremental load that cannot be accommodated at present. Figure 5.0 - 6 below provides the map of the related Mississauga intensification.

Figure 5.0 - 6: Mississauga Downtown Intensification



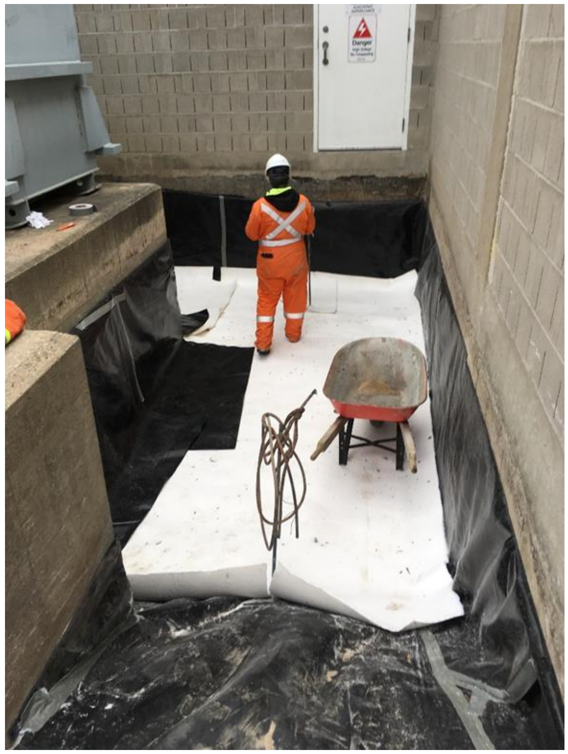
(iv) Take advantage of opportunities to establish additional linkages between legacy systems and balance loads across its entire service area so as to mitigate the need for system expansions.

Alectra Utilities plans to make targeted investments in establishing additional connections between adjacent legacy systems to assist it in balancing loads more effectively, thereby enabling it to defer the need for most costly system expansions. For example, Erindale TS capacity relief was proposed by constructing a new station as indicated in the DSP for the Enersource Rate Zone, as filed in Alectra Utilities EDR application on July 07, 2017 (EB-2017-0024). In the Enersource DSP, the construction of a station, Mini-Britannia MS, was proposed. However, as a result of planning capital investments on an integrated and system-wide basis, a more prudent option was identified, linking two of the predecessor Enersource's and Brampton Hydro's distribution systems and will result in capital savings from mitigating the need to build the new MS.

(v) Mitigate the need to rebuild or construct new stations by enhancing the use of monitoring technologies, investing in environmental protection measures and strategically managing inventory on a consolidated basis.

Alectra Utilities plans to focus investment on renewing key equipment that is associated with controlling, monitoring and protecting core system assets, where equipment is deteriorated, obsolete and/or which adversely affects reliability. In addition, investments in monitoring equipment, along with investments in oil spill containment, will lead to significant capital savings by enabling the company to defer station renewal investments. Monitoring solutions provide operators with more real-time data, that can be used to proactively manage performance through maintenance and also allow more visibility to planners on the condition of the asset to better identify when and where station rebuilds or equipment replacements are necessary. Spill containment systems enable Alectra Utilities to defer transformer replacements by operating the assets beyond the typical useful life, without the risk of environmental contamination in the event of a failure. Without such oil containment, Alectra Utilities would be required to replace these transformers sooner to mitigate the risk of environmental contamination. Figure 5.0 - 7 illustrates the installation of the Oil Containment System. Alectra Utilities implements a multi-layer passive secondary containment which uses geosynthetics material to contain hydrocarbons that may be spilled. These materials allow water to flow freely through them however when hydrocarbon comes in contact with them they congeal and seal, preventing the hydrocarbons from escaping the containment area.

Figure 5.0 - 7: Installation of Oil Containment System



5.0.1 DSP STRUCTURE AND FORMAT

This DSP is organized into four sections, which are generally named and numbered consistent with the DSP Filing Requirements, as follows.

- **Section 5.1 – Alectra Utilities' Distribution System** – This section provides a summary description of the company's service area, its distribution system and its customers, which provides context for the DSP overview provided in section 5.2.
- **Section 5.2 – Distribution System Plan –** This section provides an overview of: the relevant planning processes and the information filed in the DSP, including customers' needs, priorities, and preferences; the various elements and outcomes that were considered by Alectra Utilities in developing its capital expenditure plan; its efforts to coordinate planning with third parties and measure performance for continuous improvement; and a summary of the resulting plan.
- **Section 5.3 – Asset Management Process** – This section describes: Alectra Utilities' distribution system assets; its asset management and asset lifecycle optimization

practices, as well as the investment planning process it used to identify the specific portfolio of investments to achieve desired outcomes, and which are included in its capital expenditure plan.

- **Section 5.4 – Capital Expenditure Plan** – This section describes Alectra Utilities' capital expenditure plans for its distribution system, on an integrated basis, for the 2020 to 2024 period, and considers these plans relative to historical capital spending, where possible. The capital expenditure plans are the outcome of the asset management and investment planning processes described in section 5.2, which have been informed by the various drivers that are set out in section 5.1. The capital expenditure plan includes a series of 20 investment summaries, which describe certain groups of investments. The investment groups are organized based on the OEB's four investment categories. In addition, the capital expenditure plan includes the individual business cases for the numerous material projects underlying each of the investment groups.

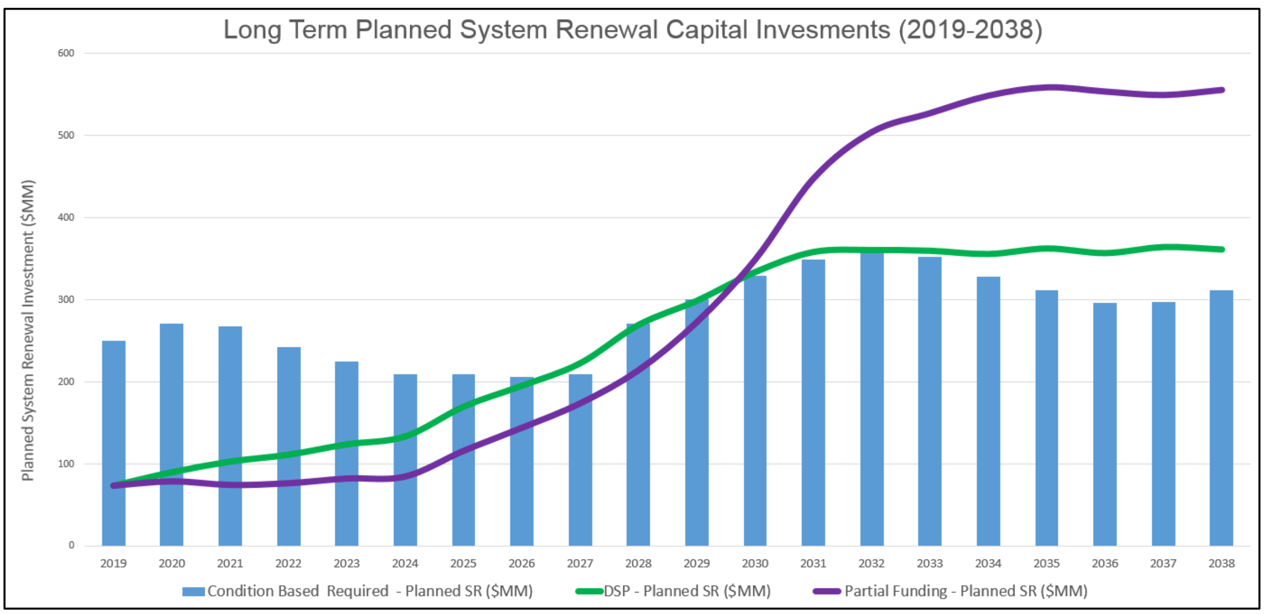
As noted, the planning period for the DSP is 2020 to 2024. As such, the DSP includes certain information for the 2015 to 2018 Historical Years, the 2019 Bridge Year and the 2020 to 2024 Forecast Years. It is important to note that, since Alectra Utilities was recently formed in 2017 and this DSP is the company's first effort to plan capital expenditures on a system-wide basis, historical information on capital expenditures and System O&M expenses are not available on a consolidated basis for 2015 or 2016, nor would such provide a meaningful basis for considering the company's plans for the 2020 to 2024 period. As such, Appendix P – Historical Capital Expenditure to DSP Section 5.2.1 provides historical expenditure data for 2015 and 2016 for each of the five predecessor utilities on an individual basis for the sole purpose of satisfying the DSP Filing Requirements. As historical system performance data remains valid when presented on a consolidated basis, this is included in the DSP.

All information used for the asset condition assessment in the DSP is based on September 2018 condition data. The feeder loading, asset utilization and load forecast information used for purposes of this DSP was attained as of October 31, 2018. Reliability metrics, analysis, and outage information include data up to December 31, 2018.

As a commercial enterprise and like other utilities regulated by the OEB, Alectra Utilities' capacity to make investments is limited by its ability to recover such through incremental cash flow including a reasonable cost of capital on associated financing. As set out in the Summary of

Requests for Alectra Utilities (Exhibit 2, Tab 1, Schedule 1), the gap between the capital investment required over the 2020-2024 period, as supported in detail by this DSP, and the level funded through the utility's base rates is approximately $60MM per year. Alectra Utilities' customers expect the utility to maintain the distribution system's reliability and accept the rate increase required to do so, as was identified in the Customer Engagement results. When presented with investment options, Alectra Utilities customers indicated preference to fund the level of investment recommended by Alectra Utilities. Accordingly, Alectra Utilities has proposed a mechanism by which capital funding can be provided on a stable, predictable basis over the 2020-2024 period, as set out in the Application Summary. Without the funding requested in this application, the utility will not be able to execute the DSP and will therefore not be able to achieve the outcomes that its customers expect.

Figure 5.0 - 8: Long-Term System Renewal Trends



If Alectra Utilities is unable to invest in system renewal at the level set out in the DSP, the result will be an increasing population of deteriorated assets, leading to a "snowplow" of capital costs for future customers. As illustrated in Figure 5.0 - 8, the system renewal investment proposed in the DSP (the green line) is already significantly below the level that the condition of the utility's assets stipulate. However, if the DSP is not fully funded (i.e., the purple line), the result will be a significant increase in renewal investments over the long term (assuming Alectra Utilities is able to secure resources necessary to execute such a plan). In the meantime, customer reliability is likely to decline further, and inefficient reactive capital expenditures would likely increase.

Should Alectra Utilities not receive sufficient funds to implement the renewal as proposed in this DSP, Alectra Utilities will have to defer essential system renewal investments which are projected to have a significant negative impact on reliability. Under the partial funding scenario reflected in Figure 5.0 - 8 (i.e., purple line), Alectra Utilities' customers would experience a projected worsening of reliability by 50% over the next five years, and a further deterioration of 112% over the next ten years, relative to the most recent five-year outage duration average.

5.1 ALECTRA UTILITIES' DISTRIBUTION SYSTEM

As this is the first 5-year DSP that Alectra Utilities has prepared on an integrated basis for its entire distribution system, it is important to provide a high-level description of the company's distribution system, its service area and the customers it serves so as to establish the appropriate context for understanding the asset management and investment planning processes and outcomes that follow. Alectra Utilities' distribution system is described in greater detail in DSP Section 5.3.2.

Given that Alectra Utilities has planned and will be implementing its capital investments on an integrated basis, its distribution system must be understood as a single system rather than as a collection of individual systems under common ownership. The company's single-system approach to planning its capital investments is consistent with the OEB's desire to have consolidated entities operate as one entity as soon as possible after consolidating, which in the OEB's view is in the best interests of consumers.[3] The investment plans identified through this DSP are therefore key to unlocking the efficiencies and customer benefits of the consolidation transactions that made Alectra Utilities what it is today.

5.1.1 SERVICE AREA

Alectra Utilities is the largest municipally-owned electricity utility in Canada, by customer count. Its distribution system serves over 1 million customers across a service territory that includes urban and rural areas and which, in total, covers an area that is approximately three times the size of the City of Toronto.[4] As shown in Figure 5.1 - 1 and Table 5.1 - 1, the system serves the following 17 communities, which the company has organized into four operating areas:

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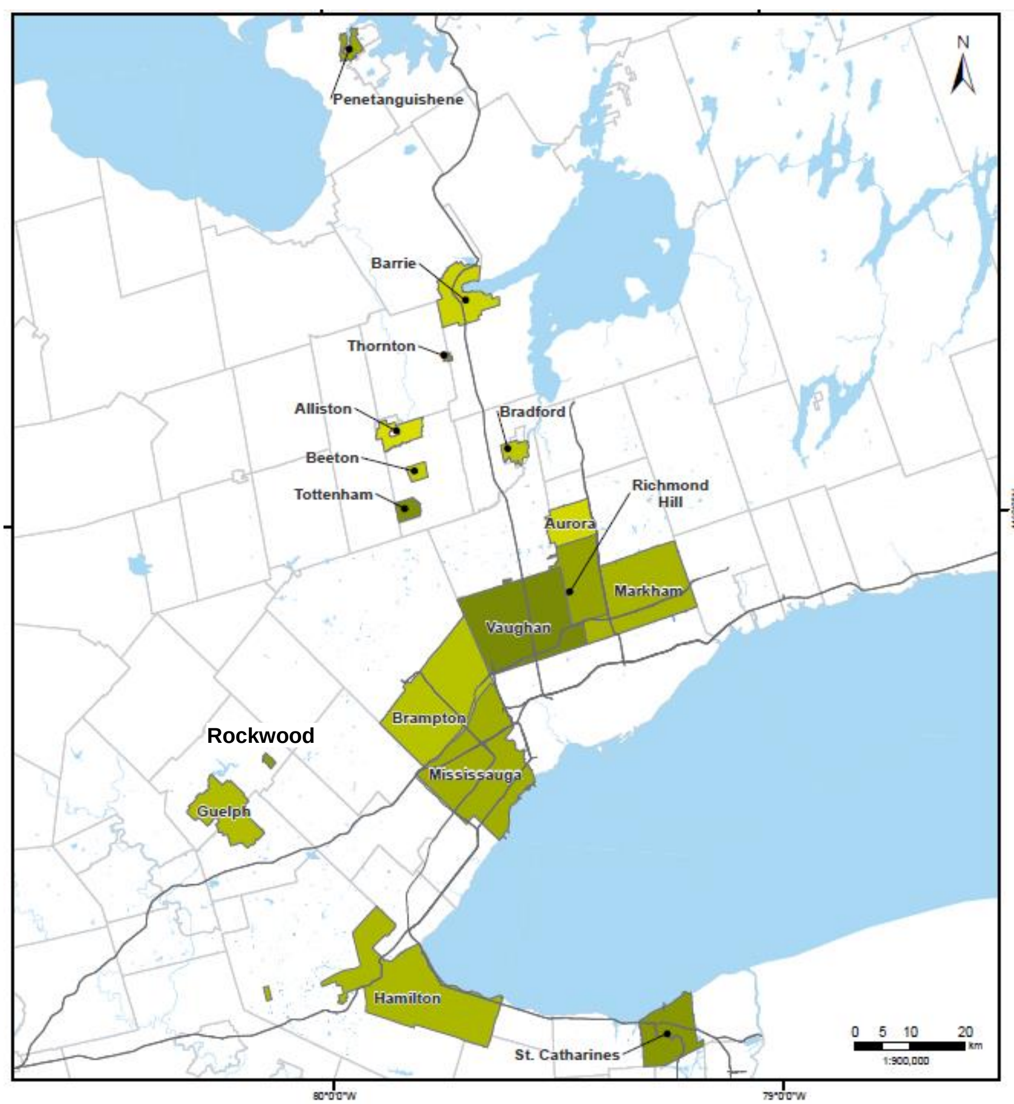
[3] *Handbook to Electricity Distributor and Transmitter Consolidations*, p. 13.
[4] Alectra's service area is 1826.6 km^2. The area of the City of Toronto is 630 km^2.

Table 5.1 - 1: Alectra Utilities' Operating Areas

Operating Area	Municipality
East	Alliston, Aurora, Barrie, Beeton, Bradford, Markham, Penetanguishene, Richmond Hill, Thornton, Tottenham, Vaughan
Central	Brampton (North), Mississauga (South)
West	Hamilton, St. Catharines
South West	Guelph, Rockwood

Figure 5.1 - 1: Alectra Utilities' Service Area



Alectra Utilities' customer base and its distribution system are growing rapidly as a result of urban expansion into adjacent rural areas in a number of the municipalities that it serves, as well as from urban redevelopment and intensification of downtown areas and transit corridors in a number of locations within its service area.

- Markham and Brampton are both key areas of expansion into adjacent rural areas.
- Significant transit corridors and light rapid transit ("LRT") developments are underway and/or planned in Mississauga, Brampton and Hamilton.
- Key areas of urban redevelopment and intensification include the Vaughan Metropolitan Centre, the Square One area in downtown Mississauga, Port Credit, downtown Hamilton, and the Brampton City Centre.

These development activities are key drivers for Alectra Utilities' System Service and System Access capital investment needs.

Consistent with the high level of development activity, population and employment levels are also growing rapidly in the company's service area. Although growth levels are not consistent among the municipalities that Alectra Utilities serves, the overall population in its service territory is expected to increase at an average rate of 1.7% per year over a 10-year period, from approximately 3.5 million in 2016 to approximately 4.1 million by 2026. Increased population and employment levels are also driving Alectra Utilities' investment needs.

5.1.2 SCOPE OF THE DISTRIBUTION SYSTEM

As of December 2018, Alectra Utilities' distribution system is comprised of approximately $4.5 billion in assets. Alectra Utilities' customers are served by 1,406 feeders at five different primary voltages: 44kV, 27.6kV, 13.8kV, 8.32kV, and 4.16kV. Alectra Utilities' assets include station assets for 14 transformer stations and 155 municipal stations, along with over 38,000 km of distribution line assets. The station assets include a total of 295 transformers (including spares), along with over 1,200 circuit breakers and reclosers, over 350 switchgear, and approximately 2,000 protection and control relays (microprocessor, solid state and electromechanical). The distribution line assets include approximately 16,400 km of overhead conductors supported by nearly 4,000 overhead switches and approximately 130,000 wood and concrete poles, over

22,000 km of underground primary cables, plus approximately 79,500 padmounted transformers, 32,000 pole-mounted transformers and 13,500 vault transformers.

Alectra Utilities is a summer peaking utility, with peak demand correlating closely with temperature. In 2018, Alectra Utilities' system served a non-coincident peak load of over 5,500 MW, which was an increase of approximately 6.5% from 2017. Relative to the 2018 Ontario electrical system peak demand of 23,240 MW[5], on Sept 5th 2018, Alectra Utilities coincidental peak demand (including Guelph) on that day and time was 5,378 MW which represents approximately 23% of the province's peak demand.

In order to serve its large territory, Alectra Utilities operates three administrative offices (Derry Road, John Street, Cityview Boulevard) as well as eight operational centres (Addiscott, Sandalwood, Jane Street, Mavis Road, Nebo Road, Patterson Road, Vansickle Road and Southgate Drive). The distribution system is currently operated from five control rooms that the company expects to consolidate over the course of this DSP period into two control rooms, each acting as a back-up to the other. Alectra Utilities is an embedded distributor to Hydro One Networks Inc. ("HONI") for specific feeders in the East, Central and West operating areas and HONI is an embedded distributor to Alectra Utilities for specific feeders in the Central operating area.

5.1.3 CUSTOMERS

Alectra Utilities serves a diverse base of customers with respect to size, industry and energy demands. Residential customers form approximately 90% of the customer count, while accounting for approximately 29% of the total load. Alectra Utilities serves approximately 950,000 residential customers, 84,000 General Service customers with less than 50 kW demand, 13,700 General Service customers with greater than 50 kW demand, and 32 large users.

Since inception in 2017, Alectra Utilities has engaged with its customers on capital planning-related issues at least once per year. The utility's customers have consistently said that they want the utility to maintain a reliable distribution system, even if that means some increase in their distribution rates. At the same time, customers have also indicated that the price of electricity is important. For residential customers, price is typically the first priority, whereas large customers

[5] "2018 Electricity Data" IESO URL: http://www.ieso.ca/en/Corporate-IESO/Media/Year-End-Data

tend to prioritize reliability above price. Across all customer segments, reliability and price have consistently been the top two priorities. As described in this plan, Alectra Utilities' 2020-2024 DSP was developed in a manner that responds to customer expectations that the utility maintains reliability but do so in a way that is prudent and delivers the best long-term value.

5.2.1 DISTRIBUTION SYSTEM PLAN OVERVIEW

This Distribution System Plan ("DSP") provides a comprehensive and detailed description of Alectra Utilities' capital investment plans for its distribution system over a planning period from 2020 to 2024. The DSP includes information for the 2015 to 2018 Historical Years, the 2019 Bridge Year, and the 2020 to 2024 Forecast Years.[6] All information used for the asset condition assessment in the DSP is based on September 2018 condition data. The feeder loading, asset utilization and load forecast information used for purposes of this DSP is as of October 31, 2018. Reliability metrics, analysis, and outage information include data up to December 31, 2018.

Alectra Utilities' investment plans are the outcome of its extensive business planning efforts, coordinated planning with third parties, multiple rounds of ongoing formal and informal customer engagement, and the implementation of a robust asset management process. This DSP, which describes these efforts in significant detail, demonstrates how Alectra Utilities has aligned its Asset Management and Capital Investment Planning processes, and their intended outcomes, with the needs, priorities, preferences of its customers, and with the principles and expectations of the OEB. Guided by the overriding objective of providing value for money, Alectra Utilities' DSP is designed to address and appropriately balance the needs and preferences of its customers, its distribution system requirements, and relevant public policy objectives.

This section provides an overview of Alectra Utilities' DSP. It is divided into the following topics, including:

i. **Corporate Strategy and Objectives:** Alectra Utilities' corporate mission, values and objectives that have guided its investment planning;

[6] Information regarding capital expenditures for the 2015 and 2016 Historical Years is based on the capital plans of Alectra Utilities' individual predecessor utilities, which approached capital spending in a manner specific to their individual needs. This document represents Alectra Utilities' first DSP, and is a comprehensive plan that takes into account and balances system needs across its entire service territory. The 2015 and 2016 historical capital expenditure information has been prepared for purposes of meeting the Filing Requirements by mapping these historical expenditures for the individual predecessor companies to current activities where possible. As the 2015 and 2016 capital expenditure decisions were not made by Alectra Utilities but, rather, by separate corporate entities, that historical capital expenditure information does not provide an appropriate basis for comparison or from which reasonable conclusions can be drawn. See Appendix P – Historical Capital Expenditure for the historical expenditure data for 2015 and 2016 for each of the five predecessor utilities on an individual basis, which is provided for the sole purpose of satisfying the DSP Filing Requirements.

ii. **OEB Policy:** Key elements of the OEB's policy framework that have informed the planning process;

iii. **Guiding Asset Management Principles**: Principles that reflect the outcomes that it seeks to achieve by implementing the planned investments, including the key drivers underlying those investments;

iv. **Asset Management Framework:** Key steps in its asset management and investment planning processes

v. **Customer Engagement**: Alectra Utilities engagement with its customers and consideration of their feedback regarding their needs, priorities and preferences as part of its investment planning process;

vi. **Coordinated Planning:** Coordinated planning with third parties that has informed the plan;

vii. **Grid Modernization**: Summary of Alectra Utilities' approach to grid modernization, distributed energy resources, responding to extreme weather events, and alignment with the Long-Term Energy Plan ("LTEP");

viii. **Capital Investment Plan:** Summary of the investment planning process and proposed Capital Investment Plan arising from the Asset Management Framework, policies and practices;

ix. **Cost Savings:** Sources of cost savings expected to be achieved through the DSP; and

x. **Third Party Review**: Summary of the objective conclusions reached by third party reviewers that reviewed the asset condition assessment and the overall DSP.

5.2.1.1 CORPORATE STRATEGY AND OBJECTIVES

Alectra Utilities' investment planning process has been guided by its Corporate Strategy, which was established by Alectra Utilities' Executive Management Team on March 1, 2017 and endorsed by its Board of Directors. The Corporate Strategy is reviewed annually by the Executive Management Team to ensure the business is aligned with current industry trends, meets regulatory requirements, and is guided by customer needs, priorities, and preferences. The Corporate Strategy is articulated through Alectra Utilities' corporate vision, mission, and values, as follows:

- <u>Corporate Vision</u>: To be Canada's leading electricity distribution and integrated energy solutions provider, creating a future where people, businesses, and communities will benefit from energy's full potential.

- <u>Corporate Mission</u>: To provide customers with smart and simple energy choices, while creating sustainable value for communities, customers, shareholders and employees.

- <u>Corporate Values</u>:

    - **Customer Focus** – Earn and keep our customers, by delivering value, while acting as a trusted advisor and strategic partner.
    - **Innovation –** Drive the business forward through continuous improvement (and integration) of people and processes with technology.
    - **Excellence** – Make the complex simple and continuously improve our performance.
    - **Quality –** Foster our fundamentals at the highest level of safety, reliability and dependability.
    - **Respect –** Ensure a respectful and rewarding work environment for all employees by collaborating as one team and acting with integrity.
    - **Community –** Provide sector-leading service and partner to build sustainable communities.
    - **Sustainability** – Balance economic efficiency, social equity and environmental accountability.

The company's vision, mission, and corporate values are incorporated into Alectra Inc.'s Corporate Strategic Plan. Alectra Utilities' strategic goals and objectives are a subset of Alectra Inc.'s Corporate Strategic Plan. The Goals and Objectives relating to the regulated distribution business conducted by Alectra Utilities, and encompassed by Alectra Inc.'s Corporate Strategic Plan, are the following:

- optimizing operations and enhancing the customers' experience, and
- building corporate resilience.

These specific Corporate Strategic Goals and Objectives are summarized in Table 5.2.1 - 1.

Table 5.2.1 - 1: Asset Management Related Corporate Objectives (by Theme)

Themes:	Optimizing Operations and Enhancing Customer Experience	Building Corporate Resilience
Strategic Goals:	Optimize the operation of assets and related processes and enhance customer experience in a financially prudent manner.	Invest in our people and processes to meet the needs of our customer and stakeholders.
Strategic Objectives:	• Optimize operations and lifecycle management and related processes regarding asset renewal to maintain reliability and customer service levels. • Invest in and leverage emerging technologies to enable operations, maintain reliability, integrate conservation & demand management and distributed generation activities. • Proactively enhance customer engagement and levels of service through levering various channels/technologies. • Maintain and continue to improve upon our strong safety record.	• Service organic growth requirements. • Be a focused, sustainable and flexible organization positioned to succeed in the evolving market, in the energy industry and in the face of increasing extreme weather. • Strengthen the development and engagement of employees. • Continuously optimize business practices and processes to best-in-class performance.

Alectra Utilities' Asset Management Principles have necessarily evolved from asset management and investment planning based on the historic operating zones of the predecessor utilities to the more efficient management of assets and planning of capital investments on a system-wide basis. System-wide planning enables the company to take advantage of opportunities to optimize and establish links between Alectra Utilities' legacy systems so as to make maximum use of capacity, balance loads over a larger service area, and enable better back-up support for contingencies without necessarily expanding the system.

The DSP process and the resulting Capital Investment Plan have been informed by a comprehensive customer engagement process to ensure Alectra Utilities' investments are planned to address customer identified needs, priorities, and preferences. As described in more detail further below, Alectra Utilities' Asset Management Process began with an independent assessment of customers' needs and priorities, before specific investments are identified by Alectra Utilities project owners. Once potential investments were identified, Alectra Utilities returned to customers for a second time to assess their preferences between specific investment options and outcomes. In that second phase of customer engagement, the utility's customers identified strong preference for Alectra Utilities to invest in system renewal, specifically the underground asset renewal, transformer replacement, rear lot and voltage conversion. Customers also demonstrated a preference for the company to invest in its overhead systems so as to enhance resilience to more frequent and more intense adverse weather conditions and to improve Alectra Utilities' ability to restore service expeditiously. In response to these reliability concerns, the DSP identifies and addresses areas of its overhead system where reliability is deteriorating and the system is most vulnerable to adverse weather events. Outcomes from the second phase of Customer Engagement are provided in details in the Innovative Report included as Appendix 1.0 of C02 – 2020-2024 DSP Customer Engagement.

The Corporate Strategy also establishes an objective of meeting the organic growth needs of the business through integrated planning approaches that enhance reliability and affordability. This goal is supported by the DSP's focus on being responsive to anticipated needs in areas of new greenfield development and urban redevelopment/intensification, as well as by Alectra Utilities' plans to establish additional linkages between its legacy systems and to balance loads across its entire service area to mitigate the need for system expansions.

Additionally, Alectra Utilities' planned investments in environmental protection measures and enhanced use of monitoring technologies at its stations are consistent with its corporate values of pursuing superior environmental performance and advancing the business through continuous improvement by utilizing technology.

5.2.1.2 OEB POLICY FRAMEWORK

The DSP is also guided by the OEB's policy framework. The company has been mindful of and has made significant efforts to develop a DSP that will further the following outcomes, which the OEB in its *Renewed Regulatory Framework* ("RRF") found to be appropriate for distributors and which were further articulated in the OEB's *Handbook to Utility Rate Applications*:[7]

- Customer Focus: Utilities are expected to develop a genuine understanding of their customers' interests and preferences and reflect those interests and preferences in their business plans. Utilities are expected to demonstrate value for money by delivering genuine benefits to customers and by providing services in a manner which is responsive to customer preferences;
- Operational Effectiveness: Utilities are expected to demonstrate ongoing continuous improvement in their productivity and cost performance while delivering on system reliability and quality objectives. Utilities are expected to demonstrate value for money by presenting plans for delivering services that meet the needs of their customers while controlling their costs;
- Public Policy Responsiveness: Utilities are expected to consider public policy objectives in their business planning and to deliver on the obligations required of regulated utilities; and
- Financial Performance: Utilities are expected to demonstrate sustainable improvements in their efficiency and in doing so will have the opportunity to earn a fair return.

Alectra Utilities has developed a DSP that achieves an appropriate balance between the outcomes set out in the OEB's policy framework. The company's DSP enables it to address a broad range of vital needs: to meet compliance requirements, to prudently manage the distribution system assets, to mitigate health and safety risks, to be responsive to identified customer interests and preferences, to continuously improve productivity and cost performance, to maintain reliability and quality of electricity service, to promote innovation and modernization, to be responsive to public policy objectives, and to achieve sustainable improvements in financial performance.

[7] See Handbook to Utility Rate Applications, pp. 2-3.

5.2.1.3 GUIDING ASSET MANAGEMENT PRINCIPLES, INVESTMENT DRIVERS AND PLANNED OUTCOMES

Based on the guidance from its Corporate Strategic Objectives and from the OEB's policy framework, Alectra Utilities has developed a set of Asset Management Principles specifically to guide its asset management and investment planning processes. The Asset Management Principles were presented to business unit leaders and project owners prior to identification of investment needs so as to ensure that capital investment planning outcomes would align with the Corporate Goals and Objectives. These principles reflect the outcomes – financial, customer, operational, regulatory, and organizational – that Alectra Utilities expects to realize from implementation of the DSP, and are as follows:

- <u>Customer:</u>
    - Evolve the distribution system to increase Alectra Utilities' ability to meet current and future customer needs through a range of traditional and emerging solutions.
    - Identify, understand and incorporate customer preferences and priorities to enable the appropriate integration of solutions, products and services on the grid.
- <u>Financial</u>:
    - Prudently invest and maintain assets to provide sustainable value through the optimal allocation of resources in response to relevant risks, compliance requirements, and performance targets.
- <u>Operational:</u>
    - Enhance operational effectiveness and system performance in alignment with Alectra Utilities' long term plans by balancing the need for system renewal, system modernization, and cost mitigation.
    - Prepare the distribution system for new technologies, while controlling costs and optimizing system utilization.
    - Increase monitoring, analytics and business intelligence capabilities to support operational excellence and continuous improvement.

- Regulatory:
    - Ensure alignment between asset management and regulatory requirements and policies, including Ontario's *Long-Term Energy Plan*.
- Organization:
    - Empower internal resources to innovate and develop flexible solutions.
    - Develop diverse competencies to enable nimble adaptation to change, as driven by fact-based decision making and business intelligence.
    - Leverage and adopt technology solutions to increase collaboration on an enterprise-wide basis and across Alectra Utilities' service area.

By applying these outcome-based principles to its asset management and investment planning processes, Alectra Utilities has developed a capital investment plan that addresses a set of well-defined, priority needs that are aligned with the desired outcomes. The following priority needs are reflected throughout the DSP and are key drivers of the planned investments:

- reducing outage impacts from deteriorating underground systems;
- enhancing the resiliency of overhead systems and thereby reduce outage impacts from adverse weather events;
- preparing for and being responsive to anticipated growth needs in areas of new greenfield development and urban redevelopment/intensification;
- mitigating the need for system expansions by taking advantage of opportunities to establish additional linkages between legacy systems and to balance loads across its entire service area;
- mitigating the need to rebuild existing stations by enhancing the use of monitoring technologies, investing in environmental protection measures and strategically managing inventory of spare station equipment on a consolidated basis; and
- enhancing grid integration, which enables continued conservation and demand management and the implementation of emerging technologies, such as distributed energy resources.

Significant investments are needed to address the priority needs of the distribution system. By investing to mitigate the need to rebuild stations, Alectra Utilities will be able to focus on renewing its underground systems, meeting customer needs resulting from urban development and intensification, and on making targeted investments to increase the resilience of its overhead systems to adverse weather events. It is particularly important for Alectra Utilities to focus on its underground systems to address the significant declining reliability customers have experienced as a result of underground cable failures.[8] Please refer to DSP Section 5.4.3 Appendix A10 – Underground Asset Renewal for a details of the company's plans to renew its underground distribution system.

The deteriorating reliability of its underground systems is a result of several interrelated factors that have challenged Alectra Utilities. In particular, the company has faced a growing need for system access investments, over which Alectra Utilities has little control. This has eroded its capacity to invest in system renewal work, such as is the investments needed on its underground systems. While Alectra Utilities has generally been able to accommodate the growing need for mandatory System Access work by deferring System Renewal investments, this practice is not sustainable or prudent. The outage data demonstrates that further deferral of System Renewal investments will lead to significant consequences for customer reliability.

The relative under-investment in System Renewal is also due to the fact that Incremental Capital Module ("ICM") funding has not been available for many of the company's planned capital investments, particularly in the System Renewal category. As described in Exhibit 2, Tab 2, Schedule 2, the OEB has determined that the ICM is unable to accommodate many of the investments needed to maintain Alectra Utilities' distribution system. In particular, ICM funding is not available for "typical annual capital programs" or smaller projects that do not on their own meet an undefined, secondary materiality threshold.[9] Accordingly, Alectra Utilities has proposed the M-Factor: a new capital funding mechanism that is capable of funding the prudent capital investments that are required throughout the deferred rebasing period, as set out in this DSP.

5.2.1.4 ASSET MANAGEMENT FRAMEWORK

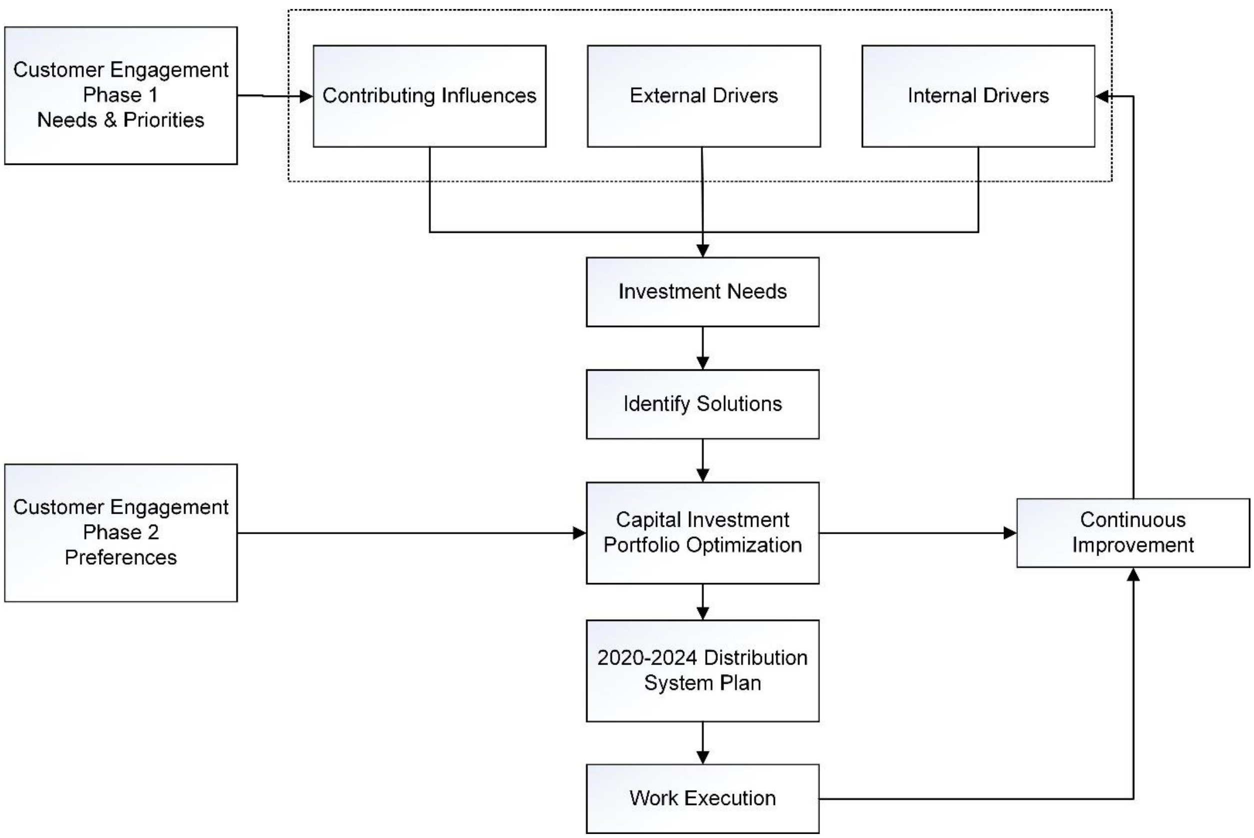
Alectra Utilities' Asset Management Framework provides a foundation for the DSP, and serves as the basis for all capital investments. Asset Management decision-making is focused on balancing asset performance with the long-term value of the investment. Alectra Utilities strives

[8] An average annual 8% increase in outage frequency, as well as the average annual increase in outage duration.
[9] EB-2017-0024, Decision and Order, April 6, 2018, p. 30.

to maintain the lowest possible long-term cost of asset ownership, considering and balanced against delivering on customer needs, priorities, and preferences and adhering to electrical system design requirements and standards, construction codes and prescribed asset and manufacturing specifications.

Alectra Utilities' Asset Management Framework is explained in detail in section 5.3.1, and the Asset Management Process is depicted at a high level in Figure 5.2.1 - 1 below.

Figure 5.2.1 - 1: Overview of the Asset Management Process



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

i. **Contributing Influences**: This category consists primarily of customer input, as reflected in DSP-specific customer engagement and ongoing contact between Alectra Utilities and its customers. Other contributing influences include responsiveness to renewal energy generation demands, technical obsolescence and emerging technologies. The various stages of customer engagement that informed the DSP are described in the following section.

ii. **External Drivers**: External mandates that Alectra Utilities must satisfy, either as conditions of the utility's license or otherwise as required to meet external requirements (such as public safety).

iii. **Internal Drivers**: Corporate Objectives determined by Alectra Utilities' management, such as reliability or customer service goals that are in alignment and meet or exceed objectives set for distributors by the OEB.

Alectra Utilities' DSP is designed to be responsive to investment needs identified from these drivers, described in detail in Section 5.3.1. Once investment needs are identified, Alectra Utilities identifies solutions and develops business cases with feasible technical alternatives for potential investments. Through the optimization process, described below, and based on further input from customers on specific preferences, Alectra Utilities refines the potential investments into a distribution system plan that will deliver the identified outcomes and the best long-term value.

After the formation of Alectra Utilities in 2017, the company developed the Asset Management Process by consolidating and harmonizing the asset management processes of its predecessor utilities. The result is a harmonized, uniform and systematic Asset Management Process to collect, assess, evaluate, prioritize and optimize system and operational needs based on current and expected future system operating conditions. On this basis, Alectra Utilities is able to ensure that all system and operational needs are considered for the diverse operating zones across its service territory, in alignment with all relevant considerations, including customer preferences and priorities, regional planning requirements, public policy and government directives, Alectra Utilities' Corporate Objectives as well as OEB's RRF performance outcomes.

In order to ensure distribution system needs are considered consistently and objectively, Alectra Utilities undertakes risk management, system capacity and Asset Condition Assessment ("ACA") reviews. Starting in 2017, Alectra Utilities harmonized and consolidated its ACA practices for distribution and station assets. The consolidated ACA practices reflects Alectra Utilities approach to support the effective and efficient planning of capital investments and its efforts to operate as a single entity. Please refer to Section 5.3.1 for a detailed description of the company's methodology for assessing asset condition as an important driver of asset investment needs.

Alectra Utilities evaluates all investment needs through a consistent and uniform process, which ensures that capital investment needs across the entire organization are afforded equal opportunity to be assessed for selection and funding. Alectra Utilities has also consolidated and harmonized system planning criteria and practices based on best practices from its predecessor utilities, ensuring that capacity forecasting and system expansion investments are identified, assessed and prioritized in a consistent manner.

A Capital Investment Optimization

In developing its Asset Management Framework, Alectra Utilities incorporated best practices from its predecessor utilities. Having regard for the utility's service area, number of customers, volume of assets, diverse capital investment needs and the size of the typical annual capital investment portfolio, the utility identified a need to implement a Capital Investment Portfolio Management System to manage the over one thousand capital investment business cases in a systematic and uniform manner, each of which represents a potential discrete investment need. Building on the relevant best practices of one of its predecessors, PowerStream, Alectra Utilities selected the CopperLeaf C55 system as the preferred solution to provide a repository for all capital project business cases and to manage the entire investment portfolio for Alectra Utilities.

Alectra Utilities implemented the CopperLeaf C55 system to provide a uniform approach to the analysis and verification of its numerous and diverse capital projects. By implementing this industry-leading solution with proven multivariate capital investment optimization capability, Alectra Utilities has the ability to run multiple investment scenarios considering financial, risk and resource driven constraints while ensuring capital investments are aligned with Corporate Objectives, public policy objectives, and customer preferences and priorities. The CopperLeaf C55 system required that Alectra Utilities develop a Value Framework (please refer to Section 5.3.1 for an introduction to the Value Framework), and a Risk Matrix that is calibrated and aligned to the company's Enterprise Risk Management ("ERM") Policy and ERM Framework.

Through the optimization process, Alectra Utilities evaluates each capital investment based on its value and risk. Leveraging the value-based decision-making capability of CopperLeaf C55, Alectra Utilities uses a rational economic approach calibrated to a common scale so that dissimilar investments (e.g. distribution system investment vs. fleet investment) can be compared based on a wide range of criteria. As explained in Section 5.4.1, Alectra Utilities has aligned the Value

Framework to its Corporate Objectives, Asset Management Strategy and ERM Framework to permit a quantitative, consistent and repeatable approach to optimizing investments across the entire organization. This results in a Capital Investment Portfolio that yields maximum value, is risk-informed, and incorporates financial and non-financial benefits and other attributes on a common scale.

5.2.1.5 CUSTOMER ENGAGEMENT

A Overview

Since its creation in 2017, Alectra Utilities has engaged with its customers on capital planning-related issues at least once per year. The utility's customers have consistently said that they want the utility to maintain a reliable distribution system, even if that means some increase in their distribution rates. At the same time, they have also said that the price of electricity is important. For residential customers, price is typically the first priority, whereas large customers tend to prioritize reliability above price. However, in all customer segments, reliability and price have consistently been the top two priorities. As described below, Alectra Utilities' 2020-2024 DSP was based on addressing customer expectations that the utility maintain reliability, but do so in a way that is prudent and delivers the best long-term value.

Customer needs, priorities, and preferences are central to Alectra Utilities' Asset Management Framework. Before the utility began assessing specific investment options for this DSP, it considered customer needs and priorities as drivers of the investment planning process (the top level of Figure 5.2.1 - 1). Once Alectra Utilities identified specific potential investments to satisfy those needs and priorities, it consulted with customers again to seek their preferences on specific investment options. Customer input from this second phase was then reflected in the capital investment optimization process that ultimately produced the investments in the DSP. Throughout this process, customer input was assessed by an independent third party.[10]

The following summarizes the multiple customer engagement activities that Alectra Utilities undertook specifically as part of preparing the capital investment plan in this DSP, as well as other

[10] In the case of this DSP, customer needs, priorities and preferences were assessed by Innovative Research Group Inc. ("Innovative Research").

ongoing forms of customer engagement, which together have informed the company's understanding of its customers' needs, priorities, and preferences.

B DSP-Specific Customer Engagement

As noted above, Alectra Utilities considers customer input at multiple stages of its Asset Management Process. Figure 5.2.1 - 2 summarizes the role that customer engagement played in preparing the DSP. Further details are provided below.

Figure 5.2.1 - 2: Customer Engagement in the Asset Management Process

Assessing Customer Needs & Priorities

- In mid-2018, Alectra Utilities consulted customers to assess their views on their needs and the outcomes they want the utility to prioritize in the 2020-2024 period.
- Innovative Research reported that, despite price concerns, customers are generally willing to consider paying more to maintain a reliable system.

Identifying Investments based on Customer Needs & Priorities

- Alectra Utilities evaluated each part of the utility's business and identified all of the projects that could provide meaningful benefits to customers
- At the first stage of preparing the DSP, Alectra Utilities instructed its planners to identify investments to address negative reliability trends
- Alectra Utilities' planners focused on identified areas and assets where customers' reliability has been poor or deteriorating
- Alectra Utilities used its best efforts to find the right balance between keeping rates down and the other outcomes that customers valued

Assessing Customer Preferences Between Specific Options

- In the spring of 2019, once a set of key investment options was identified, Alectra Utilities engaged customers a second time to assess their preferences between specific options.
- In this second phase, Innovative Research reported that customers strongly preferred investments in infrastrcture that most directly impacted their service, specifically investments in system renewal and system service

Preparing a Prioritized Capital Investment Plan Based on Customer Preferences

- To reflect customer preferences, Alectra Utilities deferred investments in DER Pilots, building of a new municipal station in Alliston, voltage conversion project, lines capacity project, several facilities projects and reduced scope replacement of smart meters.
- To reflect customer preferences and identified renewal needs, Alectra Utilities increased the pace of investment in Underground Asset Renewal
- Please see Section 5.2.1.5-D of the DSP for a summary of all adjustments made based on customer preferences

Alectra Utilities engaged Innovative Research to assist in undertaking customer engagement, specifically to support development of the DSP. With assistance from Innovative Research, Alectra Utilities completed two customer consultations for this purpose.

The first consultation was to assess customer needs and priorities, which informed the investment options that Alectra Utilities identified for the 2020-2024 period. This was conducted in mid-2018 and Innovative Research delivered its findings (including a summary “placemat”) in September 2018.[11] Innovative Research’s overall finding was that, despite price concerns, customers are generally willing to consider paying more to maintain a reliable system.[12] Based on customers’ input and other Corporate Objectives, Alectra Utilities evaluated each part of the utility’s business and identified all of the projects that could provide meaningful benefits to customers. The cost of all of the projects was greater than that which was provided for in existing electricity distribution rates. Alectra Utilities used its best efforts to find the right balance between keeping rates down and the other outcomes that customers valued.

Once it had identified a preliminary set of potential capital investments, Alectra Utilities returned to customers for a second consultation in 2019. The objective of the second consultation was to allow customers to provide feedback on whether planners found the right balance between the outcomes on particular investment options, or whether Alectra Utilities should be choosing different options that better reflect customer views. For example, Alectra Utilities customers were asked to preference on the pacing options of Underground Asset Renewal with trade-off of expected reliability outcomes. Innovative Research conducted the second consultation in the spring of 2019 and delivered their report in May 2019.[13] In the report, Innovative Research concluded that customers are prepared to fund the level of investments recommended by Alectra Utilities. Alectra Utilities’ incorporation of customer preferences is described in the relevant subsection below.

[11] The placemat is attached as Appendix C01 - Placemat – First Phase of Customer Engagement to this DSP.
[12] The findings of the first consultation are described in greater detail in the relevant subsection below.
[13] Innovative Research’s report on the 2019 consultation on customer preferences is attached as Appendix 1.0 of C02 – 2020-2024 DSP Customer Engagement.

C 2018 Consultation: Needs and Priorities

Before Alectra Utilities identified potential investments options for the 2020-2024 period, it consulted with customers to assess and gain an understanding of their needs and priorities. In this first consultation, Innovative Research used a range of techniques to identify customer needs and priorities. In order to assess the customer needs and preferred outcomes, Innovative Research implemented telephone surveys to collect the input of a random-sample of residential, small business and mid-market customers. For key account customers, Innovative research applied an online survey since Alectra Utilities had email addresses for key account customers being sampled. The application of an online survey enabled Innovate Research to maximize the completion rate for key account customers. In order to ensure that surveys included appropriate context and clear questions, Innovative Research tested the surveys in customer focus groups.

The results of the first consultation directly informed the identification of investment needs and decision-making throughout the Asset Management Process, as explained in detail in Section 5.3.1. As described in that section, Alectra Utilities' capital planning begins by identifying needs and solutions to those needs. Customers stated needs and priorities (maintaining reliability, while being sensitive to price) directly led to the set of potential investments for the 2020-2024 period, complete with identified investment solutions that included options of pacing, investment levels and corresponding outcomes for the second engagement initiative.

In the first consultation, Innovative Research identified the following customer priorities, which directly affected the identification of investment needs:

1. Charging reasonable distribution rates;
2. Ensuring reliable electrical service;
3. Reducing/managing consumption;
4. Minimizing and mitigating environmental impacts; and
5. Public and Employee Safety.

For large user customers, Innovative Research identified that ensuring reliable supply is a higher priority than distribution rates.

In terms of reliable electrical service, Alectra Utilities customers identified that the top reliability priority was to reduce the overall number of outages. Five out of eight mid-market and large user customer groups ranked reduction in the number outages as their top priority, while residential customers placed it as a second priority.

The second priority, relating to reliability, was reducing the impact of outages due to adverse weather events. Alectra Utilities' residential customers identified that mitigating prolonged outages due to adverse weather is a top priority and of highest concern. Outages due to adverse weather were also a top-three priority for small and mid-market business customers.

Customers identified the overall length of outages as the third priority related to reliable electrical service. The majority of customers ranked outage duration as the third priority, with large users also identifying power quality as a priority.

After identifying and categorizing the needs and priorities identified through the first initiative, Innovative Research gathered the input on how customers ranked these priorities. According to Innovative Research, the input received through the first of the two DSP-specific engagement initiatives can be summarized as follows:

1. The majority of customers are satisfied with the current service they receive.
2. The top priorities of customers include reasonable rates, reliability, reducing/managing consumption, environmental impacts, and safety.
3. Despite price concerns, the majority of customer are generally willing to consider paying more to maintain a reliable system.
4. A clear majority of customers support investments in system renewal and system service.
5. Customers generally agree that grid modernization can wait for the normal renewal process. Although customer needs indicate no immediate pressure to proactively invest in grid modernization, support for specific modernization projects could exceed general support.

Previously in 2017, Alectra Utilities engaged Innovative Research to assist in undertaking customer engagement specifically to support the development of capital investment plan for 2018 period. From this 2017 consultation, Innovative Research's overall finding that the top three priorities for Alectra Utilities' customers were to deliver reasonable distribution rates, ensure reliability service, and help customer reduce and better manage their electricity consumption. Based on customer input obtained in 2017, Alectra Utilities developed the Value Framework (for a detailed explanation, please refer to Section 5.3.1) to be reflective of Innovative Research's overall finding that, despite price concerns, customers are generally willing to consider paying more to maintain a reliable system. The results of the first consultation directly informed and influenced the development of the Value Framework`s measure for Reliability Benefits and the Risk Matrix. Alectra Utilities reduced the value of the Reliability Benefit measure to appropriately reflect customer priorities and emphasize cost. Further, Alectra Utilities developed the Risk Matrix (please refer to Section 5.4.1) to reflect Alectra Utilities Enterprise Risk Framework and increased the granularity of the risk impact and probability criteria so as to set more stringent measures for project value evaluations. By setting higher constraints on reliability benefits and enhanced risk granularity, Alectra Utilities reflected customer preferences of cost over reliability. The 2018 Customer Engagement results confirmed that customer priorities and needs remained consistent with the 2017 Customer Engagement results.

D 2019 Consultation: Refining the Capital Investment Plan Based on Specific Customer Preferences

Once a preliminary set of investments was identified in early 2019 (based on customer needs and preferences, and Corporate Objectives to optimize operations and enhance customer experience), Alectra Utilities returned to customers for a second consultation on specific outcomes and options for investments in the 2020-2024 period. During the second phase of customer engagement, Alectra Utilities received feedback from 32,407 customers, making this phase of engagement the largest customer consultation ever conducted in Ontario's electricity sector.

In the 2019 consultation, Alectra Utilities asked customers for their input on the following specific capital investment areas:

i. Specific Asset Renewal Investments (Cables, Poles, Transformers)
ii. Rear Lot Conversion Investments
iii. Voltage Conversion Investments
iv. Capacity Investment (Stations and Distribution Lines)

v. Control and Monitoring Equipment Investments
vi. Metering Investments to mitigate data security risks
vii. General Plant Investments
viii. Pilots to evaluate integration of emerging technology and enable customer choice

The 2019 phase of the customer engagement process focused on projects where Alectra Utilities would be more likely be able to make adjustments in response to customer preferences. Specifically, the engagement focused on a subset of projects that offered greater potential for pacing adjustments in response to customer preferences, alongside some exceptional projects that are distinct from the utility's typical capital investment categories. Although all of the projects included in the asset management process are necessary and provide value, Alectra Utilities generally has a greater ability to control the pace of the projects included in the second phase of customer engagement. In the second stage of customer engagement, Innovative Research presented customer investment options and opportunity to present investment preferences based on meaningful trade-offs between outcomes that matter to customers.

In order to provide meaningful feedback on a large portfolio of capital investments, Innovative Research developed a comprehensive workbook to present the overall scope of the DSP and to provide customer context for the investment options. The workbook was designed to provide customers an opportunity to reconsider their answers on individual investment choices after reviewing the total rate impact of their initial choices. In order to provide customers the oppourtunity to reconsider their initial choice once the total rate impact was determined, an online survey utilizing the comprehensive workbook was required.

Each Alectra Utilities customer with an email on record was sent an invitation containing a unique link to the workbook survey. To ensure that every Alectra Utilities customer was provided the opportunity to provide their preferences, Alectra Utilities provide a voluntary path for customers to participate in the online workbook and advised customers of this opportunity using social and traditional media.

Given the possibility that customers who provided an email address to Alectra Utilities may be different than customers who did not, Alectra Utilities also commissioned a reference study. The results of the representative sample were validated in two ways:

1. The respondents to the representative online workbook were compared to the known characteristics (region, consumption and rate class).
2. The respondents to the representative online workbook were also compared to key benchmarks established in the reference survey.

Based on those comparisons, weights were established to ensure the representative sample properly reflected the characteristics of the broader population of customers.

In the 2019 phase of customer engagement, Alectra Utilities customers indicated that they are prepared to fund the level of investment recommended by the utility. When respondents were shown the rate impact of their initial choices and given the opportunity to change their responses until they were satisfied. There was minimal net impact of the final customer choices relative to the initial choices. The majority of customers in all rate classes either supported the increase in rates or identified that, although they didn't like the rate increase, they feel it is necessary.

The outcomes of the 2019 phase of customer engagement identified that customers across all rate classes strongly support investments in the infrastructure that directly provides service to customers. Alectra Utilities' customers indicated a strong consensus in support of recommendations for investments that directly serve customers including investments in underground asset renewal, overhead system renewal, transformer replacement, monitoring and control equipment as well as converting rear lot services.

A majority of customers also support investments in other infrastructure such as system expansion, intensification and back-up, voltage conversion as well as distribution station capacity and additional station investments.

Relative to the infrastructure investments that most directly service customers and other wires infrastructure investments, the second phase of customer engagement identified that customers were divided in their support for investments in general plant, innovation projects and replacement of smart meters to reduce data security risks.

Given that customers felt that the recommended options effectively incorporated the outcomes from the first phase of customer engagement (refer to Appendix C01 - Placemat – First Phase of

Customer Engagement) in most key areas of investment, Alectra Utilities was able to proceed with relatively few changes to the DSP

As set out below, Alectra Utilities incorporated customer preferences into the DSP by adjusting the pace of investments and deferring certain projects:

Deferred or Reduced Investments

1. Deferral of the Neighborhood DER Pilot Project ($9.85MM) to reflect divided customer support for innovation investments to provide customer options.

2. Reduction of scope for the Residential ICON F smart meter replacement ($6.51MM) to reflect divided customer support for the project.

3. Deferral of three facilities renovation projects ($4.9MM) to reflect divided customer support for general plant investments.

4. Deferring the new Alliston 10 MVA Substation by two years, along with corresponding deferral of feeder integration ($3.7MM) to reflect customer preferences to prioritize investments on infrastructure projects such as underground asset renewal that directly service customers.

5. Deferral of voltage conversion project ($4.48MM) to reflect customer preference to prioritize investments such as underground asset renewal.

6. Deferral of lines capacity project ($4.07MM) to reflect customer preference to prioritize investments such as underground asset renewal.

Accelerated Investments

1. Accelerated the pace of Underground Asset Renewal investment, bringing forward projects totaling $22.2MM to address urgent system needs and reflect strong customer preference to prioritize investment on infrastructure projects that directly service customers.

Alectra Utilities adjusted investment in the General Plant project to upgrade the ERP system. After the 2019 phase of customer engagement concluded, Alectra Utilities became aware that Oracle, the vendor, supporting Alectra Utilities' ERP system, has transitioned from releasing major platform upgrades to that of more frequent update releases. Hence, Alectra Utilities eliminated the JD Edwards Upgrade project ($5.6MM) and increased the ERP JD Edwards Enhancements investment by $3.0MM. The net impact of this change was a decrease of investment by $2.6MM.

Alectra Utilities also made adjustments to specific projects based on updated Hydro One project scope and schedule changes. Specifically, Alectra Utilities removed the Gage TS Upgrade ($1.3MM) and included the Barrie TS Upgrade ($2.2MM) to reflect Hydro One's renewal scope and scheduled changes. The net impact of this change was an increase of $0.9MM.

Alectra Utilities also reduced its reactive renewal investments by ($4.55MM).

The overall impact of the adjustments based on customer preferences from the second round of customer engagement on the 2020-2024 Capital Investment Plan, as well as other adjustments, was a net reduction of $17.5MM.

E Ongoing Customer Engagement

In addition to the DSP-specific customer engagement described above, Alectra Utilities also engages with its customers on an ongoing basis through various processes. Alectra Utilities interacts with its residential and commercial customers regularly through its normal business practices. Most frequently, this interaction occurs within the Customer Service Department, Distribution Design, Key Account Management and Corporate Communications groups, each of which is described below.

Community Meetings for Projects - Alectra Utilities engages with its customers during the design and implementation stages of major capital work. Engagement with customers enables Alectra Utilities to understand customer concerns and preferences with respect to implementing specific capital projects impacting the area. In addition to understanding customer preferences, Alectra Utilities values the opportunity to explain the beneficial outcomes of the capital investments to the customers and provide notice of project scope, schedule and implication of construction in the area.

Key Account Management - Alectra Utilities' large commercial and industrial customers are provided with a specialized service designed to accommodate their unique needs and requirements. The Key Accounts group meets regularly with large commercial and industrial customers to provide updates on Alectra Utilities' developments and activities which may impact the customer, as well as to obtain input regarding requirements or concerns the customers may have. The feedback received through these meetings is captured and considered in the system planning process. For example, large commercial customers have identified specific reliability and power quality needs which Alectra Utilities considers and incorporates into system plans. In addition, Alectra Utilities follows up with these customers to explain how their concerns have been addressed. This ongoing engagement allows these customers to understand various Conservation and Demand Management ("CDM") opportunities to enable better management of energy.

Communications and Social Media - Alectra Utilities is committed to providing customer-centric communications. By using modern communications and social media channels, Alectra Utilities can engage with customers through the various forums that customers prefer. Leveraging social media increases the ease and convenience for customers to take part in communications, and helps Alectra Utilities to better understand, respond to and engage the attention of specific stakeholders. It enables interactive communication, which includes the exchange of information, perspective, preference and opinions, amongst multiple audiences, effectively, efficiently, and in a timely manner. The use of social media also enhances Alectra Utilities' ability to engage customers and offers greater accessibility and convenience to provide input and preference on specific issues important to customers. Through the ongoing assessment of social media and new communication media, Alectra Utilities captures and processes customer priorities and preferences related to ongoing operations and reliability. For example, insight from social media helped inform Alectra Utilities of customer demand for real-time update information and maps during outages and outage response efforts.

5.2.1.6 COORDINATED PLANNING AND CONTINGENT ASPECTS OF THE DSP

As described in greater detail in Section 5.2.2, Alectra Utilities co-ordinates its distribution system planning with a number of third parties through a variety of activities. Alectra Utilities consults regularly with it customers through customer engagement processes, customer satisfaction surveys, key account meetings, and annual load forecasting meetings with large developers. Alectra Utilities also works closely with regional and local municipal authorities, who participate in its annual load forecasting meetings. Moreover, along with gas and telecommunications utilities, Alectra Utilities participates in public utility coordination meetings initiated by the municipalities in which it operates. Alectra Utilities is also an active participant in regional planning initiatives that are led by the IESO and Hydro One, and which include participation by other distributors that are located in the various regions where the company operates. These efforts have ensured that the DSP has been developed in a manner that recognizes related planning efforts involving third parties that affect or may affect Alectra Utilities' investment plans. For example, as a result of regional planning activities in which it has been involved, Alectra Utilities has identified four projects that are part of its capital expenditure plan. These include one project each for York and GTA West Region, Barrie- Innisfil and Greater Hamilton Area Region, as shown in Table 5.2.1 - 2 below.

Table 5.2.1 - 2: 2020-2024 Alectra Utilities Capital Projects originated from Regional Planning

Region	Project Ref	Project Name	CAPEX ($MM)
York	101488	Environmental Assessment - Markham TS#5	0.72
GTA West	150357	27.6kV 25M9 Tie from JYTS at Derry Road	2.13
Barrie/Innisfil	150259	Barrie TS - Relocate Feeder and Install Metering	2.21
Greater Hamilton Area	150587	Kenilworth TS Upgrade	0.56

Through its co-ordinated planning with third parties, Alectra Utilities has also identified a number of projects where either the scope, timing or need for the project has external dependencies and, as a result, is not entirely within its control. These are as follows.

- *Road Relocation / Transportation Projects* – These are System Access investments required to facilitate road relocation or transportation projects, which are dependent on the relevant road authorities or Metrolinx, a provincial transit agency. The relevant road authorities are: for municipal roads, the local municipalities in which Alectra operates; for regional roads, the applicable regional municipality or county; and, for provincial roads, the Ministry of Transportation. Alectra Utilities is required to accommodate road relocation and upgrade projects by relocating parts of its distribution system as and when requested by these third parties. This causes Alectra Utilities to incur material capital costs, but the need, timing and scope of the work is not within the company's control and the overall volume of such relocation work can be volatile. For these reasons, Alectra Utilities intends to request approval from the OEB to establish a variance account to track differences between forecast and actual capital spending for distribution system relocation work in response to requests from road and transit authorities, as set out in Exhibit 2, Tab 1, Schedule 4**.**

5.2.1.7 GRID MODERNIZATION

Alectra Utilities' approach to grid modernization attempts to: solve the challenges of integrating conventional and renewable sources with energy storage; integrating electric vehicles and smart buildings; deploying condition monitoring; and using real time telemetry data to gain operational efficiency. Concurrently, this approach must ensure that the grid is resilient and secure to withstand growing cybersecurity and adverse weather challenges. Please see chapter 5.3.4 for additional details.

A Alignment with the Long-Term Energy Plan

Table 5.2.1 - 3 maps the Alectra Utilities response public policy and proposed 2020-2024 initiatives to the LTEP.

Table 5.2.1 - 3: Alectra Utilities public policy response and proposed 2020-2024 initiatives to the LTEP

Key LTEP Initiatives	Alectra Utilities Response and Proposed 2020-2024 Initiatives
Ontario's Fair Hydro Plan **Bill 87, Fixing the Hydro Mess Act**	Alectra Utilities has incorporated plans to update the Customer Care and Billing system and corresponding meter-to-cash processes in order to remain compliant with applicable public policy directives. Please see Appendix A18 – Information Technology Systems for additional details.
Ensuring Flexible Transmission Energy System	Alectra Utilities actively participates in the Regional Planning process and supports the flexible energy system as it relates to transmission. Please see chapter 5.2.2.
Innovating the Future	
- Electrification of Transportation	Alectra Utilities' investments in Electrification of Transportation are geared towards determining the impact of EV charging and how the large scale penetration of EVs can be managed with a minimum investment to the grid. Please see Appendix A12 - Lines Capacity.
- Grid Modernization	Alectra Utilities' Grid Modernization investments are related to improving Grid Operational Technology, Distribution Automation and investment in Digital Information and conditioning monitoring system. Please see Appendix A11 - SCADA and Automation, A14

	- System Control, Communications, and Performance and A18 - Information Technology Systems.
- Distributed Energy Resources	Alectra Utilities has proposed deployment of DER and associated platforms to further advance Alectra Utilities ability to control and monitor DERs connected to distribution network. Please see Appendix A13 Stations Capacity and Appendix A16 - DER Integration.
Improving Value and Performance for Customers	New Market Opportunities for Customers.
- Enhancing Reliability	Alectra Utilities' system renewal investments are to maintain the five year historical system performance levels and improve reliability for identified areas that are experiencing below average reliability performance.
- Cyber Security	Alectra Utilities' investments in cyber security ensure that the deployed resources and grid operations are fully secure against cyber threats. Please see Appendix A18 - Information Technology Systems.
- Right Sizing	Alectra Utilities' system renewal investments considers right sizing during system renewal planning activities. In addition, Alectra Utilities actively participates in the Regional Planning process and provides input for right sizing of the equipment on the bulk system. Please see chapter 5.2.2.

Strengthening the Commitment to Energy Conservation and Efficiency. -Savings from Conservation and Energy Efficiency	Alectra Utilities considers the existing and future Conservation and Demand Programs for all capacity and renewal projects. Please see Appendix A12 – Lines Capacity and A13 - Stations Capacity.
Responding to Extreme Weather Events	Alectra Utilities invests in resiliency projects to mitigate impacts of adverse weather. Please see Appendix A05 - Overhead Asset Renewal and Appendix A07 - Rear Lot Renewal.
Supporting Regional Solutions and Infrastructure -Regional Planning -Community Energy Planning	Alectra Utilities has incorporated capital investments reflective and responsive to regional planning activities that impact its service area. Please see section 5.2.2 and Appendix A04 – Transmitter Related Upgrades for outcomes of regional planning activities.

5.2.1.8 CAPITAL INVESTMENT PLAN

A detailed summary is provided at the beginning of section 5.4.3 of this DSP. This section provides an overview of the capital investment plan, at a high-level.

Alectra Utilities grouped its investments into the four investment 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 obligations.
- **System Renewal:** Investments that involve replacing or refurbishing system assets which extend the service life of the assets.
- **System Service:** Investments that are modifications to the distribution system to ensure that operational objectives are met and future customer requirements can be addressed.
- **General Plant:** Investments that are modifications, replacements or additions to assets where these assets are not part of the electrical distribution system (land, trucks, computers etc.).

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 system is facing significant reliability challenges that can only be addressed through sustained investment in renewing distribution equipment, especially as related to the utility's underground distribution systems and in vulnerable portions of its overhead systems to enhance resilience to adverse weather events.

Other important investment drivers include needs for system expansion to prepare for and respond to areas of urban greenfield development and urban redevelopment/intensification. Additional investments are planned to be made to lines and stations with a view to reducing the need for more costly system expansion work and more costly new stations or station rebuilds. These investments seek to take advantage of opportunities arising from the consolidation of the company's predecessor utilities to deliver benefits for customers.

A summary of Alectra Utilities' planned capital expenditures for the 2019 Bridge Year and for the 2020-2024 Forecast Period is provided below in Table 5.2.1 - 4 and Table 5.2.1 - 5, broken down by OEB investment category. As noted above, please refer to DSP Section 5.4.3 for a detailed explanation of the Capital Investment Plan.

Table 5.2.1 - 4: Annual Capital Expenditure by OEB Investment Category

Investment Category ($MM)	2020	2021	2022	2023	2024	Total
System Access	66.5	66.9	63.2	67.1	70.2	333.9
System Renewal	139.0	142.0	154.0	156.1	177.2	768.3
System Service	38.0	36.9	36.0	42.4	37.2	190.5
General Plant	39.4	34.4	35.1	30.2	24.7	163.8
Total	**282.9**	**280.2**	**288.3**	**295.8**	**309.3**	**1,456.5**

Table 5.2.1 - 5: Annual Capital Expenditure by OEB Investment Category

Investment Category	2020	2021	2022	2023	2024	Total
System Access	24%	24%	23%	23%	23%	23%
System Renewal	49%	51%	53%	53%	57%	53%
System Service	13%	13%	12%	14%	12%	13%
General Plant	14%	12%	12%	10%	8%	11%
Total	100%	100%	100%	100%	100%	100%

5.2.1.9 SOURCES OF COST SAVINGS

Alectra Utilities is committed to improving productivity and achieving efficiencies, which will drive cost savings in both capital and in Operating, Maintenance and Administration (“OM&A”) initiatives. Asset lifecycle optimization activities and enhanced asset management planning are expected to result in savings in both capital and OM&A expenditures. The follow are the most significant areas in which Alectra Utilities expects to realize costs savings as a result of effective planning and DSP execution:

A) **Operational Efficiency** – Alectra Utilities strives to create a culture of continuous improvement. The company continues to explore new methods to effectively provide value to customers through process improvements and by leveraging new technologies.

B) **Planning Effectiveness** – Through the continuous improvement of inspection, testing and maintenance planning as well as capital work program delivery, Alectra Utilities has developed a plan that paces investments while meeting the service requirements relating to its distribution system and general plant needs.

C) **Grid Modernization -** When renewing assets or evaluating projects to address assets or asset systems in order for the assets to continue to perform at an acceptable standard on a predictable basis, Alectra Utilities incorporates new technologies where feasible and appropriate. An application example of new technology includes replacing end-of-life, manually-operated switches with smart, Supervisory Control and Data Acquisition ("SCADA") controlled switches capable of remote operation. Enabling additional remote operation is expected to reduce time to restore power in the event of a fault as well as reduce crew and truck dispatch, enabling crews to focus on the execution of the investment plan outlined in the DSP.

This DSP includes projects and initiatives that are expected to result in costs savings, especially within General Plant projects. Alectra Utilities has determined that the planned renewal of underground distribution assets and general plant assets will cost less than reactive or emergency replacements, and will ensure predictable pacing of work while minimizing disruptions to customers. Given the increase in outages largely due to equipment failures and the deteriorating condition of distribution assets, the company is committed to reversing this trend.

Alectra Utilities uses many approaches to identify and pursue potential costs savings, and cost effective service delivery[14]. Alectra Utilities has focused its initial efforts on preparing the foundational systems to allow for the consistent measurement of productivity savings across Alectra. ERP and CIS are key foundational systems that will be converged and stabilized by mid-2019. The following sections summarize areas where Alectra Utilities expects to realize efficiencies during the term of the DSP:

A Enterprise Resource Planning ("ERP")

Alectra Utilities is currently implementing a single, unified ERP system (a J.D. Edwards platform) which it expects will be fully operational by mid-2019. Tracking productivity is a complex and difficult task requiring the development of necessary systems and tools aligned to the specific process being measured. Alectra Utilities has identified ancillary systems that integrate with the ERP or rely on data from the ERP system that drive potential cost savings. The ERP system and

[14] For example, the utility's initiative to improve available tool time and productivity of the internal workforce to improve overall worker efficiency by converting non-productive time to direct-work time is ongoing, and will remain a focus area.

associated chart of accounts is a critical foundation to support a framework that allows measurements of costs for discrete activities. This framework of measurements is imperative to the company's ability to identify opportunities to find efficiencies and to determine the baseline measure for evaluation in subsequent years. Not all legacy utilities had established activity-based reporting. By integrating ancillary systems with the company's ERP system, Alectra Utilities expects to increases the opportunity to identify and achieve productivity enhancements through improved data and activity reporting.

B Work Planning and Scheduling

Alectra Utilities has adopted an industry leading work planning and scheduling process as well as systems previously implemented at the predecessor Horizon Utilities. Additional cost savings have been identified through the implementation of activity-based information as an input from the ERP system. Alectra Utilities expects that this level of detail will enable it to improve labour utilization through higher ratios of tool time, reduce overtime, fleet utilization, and decrease contractor services for a total productivity savings of $2MM, annually.

C Job Costing Analysis

Alectra Utilities has adopted leading practice of job costing analysis previously implemented at the predecessor Enersource to break down the cost of activities, analyse the job costing information, make informed business decisions resulting in increased productivity, and achieve more cost-effective outsourcing. This level of detail will enable Alectra Utilities to improve job estimating and planning that yield productivity savings and reduced contractor services for a total productivity savings of $1.5MM to $3MM annually.

D Electronic Timesheets / Inventory Ordering

Alectra Utilities has adopted a job costing practice previously implemented at the predecessor Enersource. This practice is based on using electronic timesheets, which were directly linked to its ERP through a DSI platform and eliminated the need for manually processing paper timesheets and completing data entry. The ultimate vision of the DSI timesheet platform is to link it to Alectra Utilities DSI inventory scanning software. Connecting these two platforms will enable Alectra Utilities crews to order materials from stores directly from the field. This remote capability allows stores staff to pre-pick the materials and have it ready for crews; resulting in reduced wait times and having crews arrive at their worksites earlier. A high-level estimate of the productivity savings resulting from this initiative is $1.0M per year**.**

E Customer Central Intake Process

Alectra is implementing a CC&B platform that will be fully converged by mid-2019. Enhancements to this platform and associated business processes are under review for future optimization. There are however, systems that integrate with CC&B that have potential savings. Alectra Utilities is currently processing customer connections, using each legacy partner's systems and processes. They are combination of manual, semi-automated and automated activities. To support Alectra Utilities' large customer base, the company is migrating to an integrated Portal/Electronic workflow in a Central Intake business model. This system will be integrated into CC&B and utilize information from iPass and has the potential to deliver savings of $0.75MM**.**

5.2.1.10 DSP PREPARATION AND THIRD PARTY REVIEW

In order to confirm that the methodologies and approaches taken by Alectra Utilities in preparing the DSP are reasonable and appropriate, it also engaged third party experts to provide independent/ objective reviews of significant aspects of the plan, as follows.

Kinectrics Inc. ("Kinectrics") was retained to undertake an independent, third-party review of Alectra Utilities' Asset Condition Assessment ("ACA"). Kinectrics is an engineering firm, with Asset Management expertise including conducting ACAs. The focus of the Kinectrics' review was to consider the reasonableness of the ACA in serving as the basis for identifying the company's system sustainment needs. In Kinectrics' opinion, the Alectra Utilities ACA "should fulfill its intended function" and "represents a significant step in establishing corporate-wide, consistent Asset Management processes." The complete document containing the Kinectrics opinion, entitled "Kinectrics Inc. ACA Assurance Review", is attached as Appendix E. As Kinectrics further concludes in its review of the Alectra Utilities ACA:

> *"ACA methodology utilized in the report is in line with good utility practices. It provides the required input regarding condition based asset needs. ACA results are used in conjunction with other consideration to develop investment portfolio that address Alectra's sustainment needs."*

Vanry & Associates (“Vanry”) was retained to undertake an independent, third-party review of the process and methodology used to develop the Alectra Utilities’ DSP. Vanry is a management consulting firm that provides asset management services with a focus on electric utilities with experience of evaluating capital investment decisions and plans based on asset management processes. This review involved careful consideration of Alectra Utilities’ asset management practices, to understand the linkages between the inputs that drive investment needs, the processes used to prioritize and pace investments and specific performance outcomes. In Vanry’s opinion, the Alectra Utilities DSP “represents a well reasoned, fact-based assessment of the needs of the system and that it reflects the concerns of the relevant stakeholders and the desires of customers”. The complete document containing Vanry’s opinion, entitled “Alectra Utilities 2020-2024 Distribution System Plan Assurance Review”, is attached as Appendix G. As Vanry further concludes in its review of the Alectra Utilities DSP:

> *“The proposed investment plans align with what we see as being needed by the system to deliver the required performance levels and to meet the regulatory requirements. The pacing of the investments appears reasonable and reflective of a need to balance between costs and performance obligations and risks. The quality and calibre of the report, and the continually improving work that underpins it, is reflective of sound asset management processes and thinking.”*

5.2.2 COORDINATED PLANNING WITH THIRD PARTIES

5.2.2.1 OVERVIEW

Alectra Utilities' DSP is informed by its efforts to coordinate planning with a wide range of third parties, including its customers, the municipalities in which it operates, other distributors, Hydro One Transmission and the IESO. Alectra Utilities' consultations and coordinated planning activities with each of these third parties are described below. Given the significance of Regional Planning initiatives for the DSP, a more detailed discussion of the relevant Regional Planning processes and their impacts on Alectra Utilities' capital investment plan follows. Finally, this section describes Alectra Utilities' Renewable Energy Generation ("REG") investments and the IESO's comment letter relating to those investments.

5.2.2.2 CONSULTATIONS WITH CUSTOMERS

Alectra Utilities engages with its customers in a variety of ways, both formally and informally, for a range of purposes. Regular interaction occurs through Alectra Utilities' Customer Service, Conservation and Demand Management ("CDM") and Corporate Communications groups. In addition, Alectra Utilities engages with affected customers when capital work is to be performed, through town halls, presentations and focus groups. There are several methods of engagement through which Alectra Utilities receives input and feedback directly relevant to its short-term, medium-term and long-term planning of local and regional distribution-related infrastructure. The importance of doing so is underscored by the fact that Alectra Utilities' service territory is home to a number of rapidly growing communities and customers that operate important infrastructure, including large internet and banking data centres, as well as major manufacturers and commercial service providers. The key methods used to consult with customers for system planning purposes are as follows.

<u>Customer Engagement Process</u> – Alectra Utilities carries out a formal engagement process with its customers to directly support development of its DSP. Please refer to 5.2.1.5 Customer Engagement Part D for a detailed explanation of the capital investment adjustments that reflect customer preferences. This process is described in detail in [Section 5.4(a) – Capital Expenditure Plan] and 5.2.1-Distribution System Plan Overview.

Customer Satisfaction Surveys – Alectra Utilities collects feedback from various customer classes through customer satisfaction surveys**.** Please refer to section 5.3.3 to how Alectra Utilities uses the customer satisfaction survey to monitor and track progress of the implementation of the DSP. As this is Alectra Utilities first DSP as a consolidated utility there are no historical survey results that are relevant to the development of this DSP.

Key Account Meetings – Alectra Utilities' large commercial and industrial customers are provided with a specialized service designed to accommodate their unique need and requirements. Alectra Utilities' key account staff meet with assigned key account representatives annually, or as needs arise, to review and discuss electricity distribution-related issues. Through these meetings, Alectra Utilities receives feedback on reliability and power quality issues, as well as insights into customer expansion plans, which Alectra Utilities takes into consideration for purposes of its 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 and regions in which it operates to discuss the load forecast. In addition it meets with developers to discuss growth and forecasts for their planned development activities. Alectra Utilities uses these meetings to assist it in identifying and planning for new distribution system capacity and connection needs. This information is of particular interest for the purposes of planning System Access and System Service projects.

5.2.2.3 COORDINATION OF PLANNING WITH MUNICIPALITIES

Alectra Utilities consults with the municipalities and regions in which it operates for purposes of informing its distribution system planning processes. It does so through several processes, as follows.

A Load Forecasting Meetings

As noted above, Alectra Utilities holds annual load forecasting meetings that are attended by planning and development staff from the municipalities and regions in which it operates. Alectra Utilities uses these meetings to assist it in identifying and planning for new distribution system capacity and connection needs. This information is considered particularly for the purposes of planning System Access and System Service projects.

B Public Utility Coordination Meetings

Alectra Utilities participates in meetings initiated by the cities, regions and municipalities in which it operates for purposes of coordinating the activities of public utilities. These meetings are attended by municipal planning staff, gas utilities and telecommunications 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, as well as other utility construction plans, which it takes into consideration in its planning process.

C Municipal Energy Plans

In July 2013, the provincial government announced its continuing support for local energy planning and conservation through the Municipal Energy Plan ("MEP") Program, administered by the Ministry of Energy. The Ministry offers funding support to municipalities for developing and updating MEPs, which support municipal efforts to better understand their local energy needs, identify opportunities for energy efficiency and clean energy, and to develop plans to meet their goals. MEPs assist municipalities in assessing their energy use and greenhouse gas ("GHG") emissions; identify opportunities to conserve, improve energy efficiency and reduce GHG emissions; consider the impact of future growth; consider options for local clean energy generation; and support local economic development.

Alectra Utilities has been actively involved in a number of MEPs within its service area. In particular, for the City of Markham, Alectra Utilities participated in a stakeholder engagement process, was part of a working group, provided electricity consumption data and provided supporting expertise over a 4-year period leading to the development of the Markham MEP, which was endorsed by Markham's City Council in May 2018. For the City of Vaughan, Alectra Utilities participated in the development of the MEP over a 2-year period, which resulted in a plan being issued in June 2016. In 2017, Alectra Utilities provided letters of support to the City of Mississauga and to the Town of Aurora for their applications to the Ministry of Energy for funding to develop MEPs, which Alectra Utilities has committed to supporting by providing energy usage data and by participating in stakeholder engagements/steering committees. Through its involvement in the MEP development process with the communities within its service area, Alectra Utilities gains insights into municipal goals and timelines for energy consumption, as well as short- and long-term municipal energy use policy. This aids Alectra Utilities in its own long-term capacity planning.

5.2.2.4 COORDINATION OF PLANNING WITH OTHER DISTRIBUTORS

Alectra Utilities is an embedded distributor to HONI in some parts of its service area; similarly, HONI is an embedded distributor to Alectra Utilities in some parts of its service area. Alectra Utilities coordinates with the HONI by providing load forecast, planned renewal and maintenance activities. Further coordination also happens in the context of Regional Planning which is described below.

5.2.2.5 COORDINATION OF PLANNING WITH HYDRO ONE TRANSMISSION

Alectra Utilities' distribution system is supplied from 65 Hydro One Transmission Stations and 14 Alectra Utilities owned transmission stations connected to the Hydro One owned transmission grid. As such, it is critical for Alectra Utilities to consult with and coordinate system planning efforts with Hydro One's transmission business. This coordinated planning occurs through the Regional Planning Process, which includes Integrated Regional Resource Planning (led by the IESO) and Regional Infrastructure Planning (led by Hydro One Transmission). Of the 21 regions established by the IESO for planning purposes, Alectra Utilities has participated in seven regional planning processes, along with additional sub-regional planning activities in several of the regions. The Regional Planning Process and Alectra Utilities' participation in each of the regional processes, as well as the impacts of these processes on the company's capital investment plans in this DSP, are described in greater detail below. Please refer to Appendix I - Hydro One Networks Inc. - Planning Status Letter.

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 Local Advisory Committees ("LACs"). LACs provide advice and recommendations on the development of medium and long term electricity plans, as well as on how to best engage the broader community in discussions about electricity needs. As noted, the Regional Planning Process and Alectra Utilities participation in it, as well as the impacts of these processes on the company's capital investment plans in this DSP, are described in greater detail below.

5.2.2.7 REGIONAL PLANNING OBJECTIVES AND PROCESS

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

- Bulk system planning;
- Regional system planning; and
- Distribution system planning

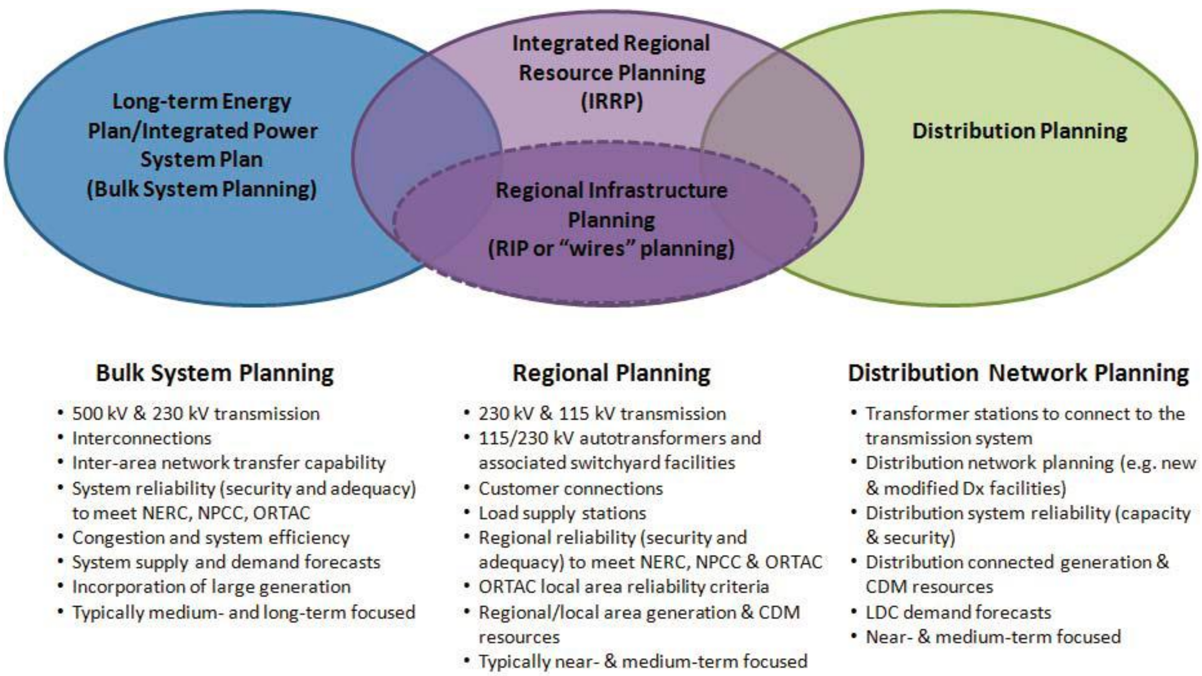
Bulk system planning typically considers the power system consisting largely of the 230 kV and 500 kV transmission network. The bulk power system transfers large quantities of power between the provincial grid and neighbouring jurisdiction power systems, external to the province via the interconnections. The bulk power system also connects major generation sources and delivers that power to major load centres in Ontario. Bulk system planning considers not only the transmission facilities ("wires") but also resources, including generation and CDM, needed to adequately supply the needs of the province. The IESO is responsible for bulk system planning in Ontario.

Regional planning considers supply and reliability issues at a regional or local area level, with a focus largely on the 115 kV and 230 kV 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 or "wires" perspective, regional planning focuses on the facilities that provide electricity to the delivery points of the transmission connected customers, including distributors. From a resource perspective, regional planning considers the local generation and/or CDM that could be developed to address supply and reliability issues in a region or local area. The planning horizons of regional facilities are typically near- to medium-term, but there may be situations where particular needs and issues may require a long-term outlook at the regional level.

Distribution system planning is carried out by Local Distribution Companies ("LDCs") such as Alectra Utilities, and looks at specific investments on the low voltage distribution system over the near and medium term, as reflected in this DSP.

Regional planning can overlap with bulk system planning. For example, overlap can occur at interface points or where regional resource options may address a bulk system issue. Similarly, regional planning can overlap with the distribution system planning, such as where the 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. To ensure efficiency and cost effectiveness, it is important for Alectra Utilities to coordinate its planning efforts with both bulk and distribution system planning through Regional Planning Processes. The scope and relationships between these levels of planning are depicted in Figure 5.2.2 - 1.

Figure 5.2.2 - 1: The Regional Planning Process[15]

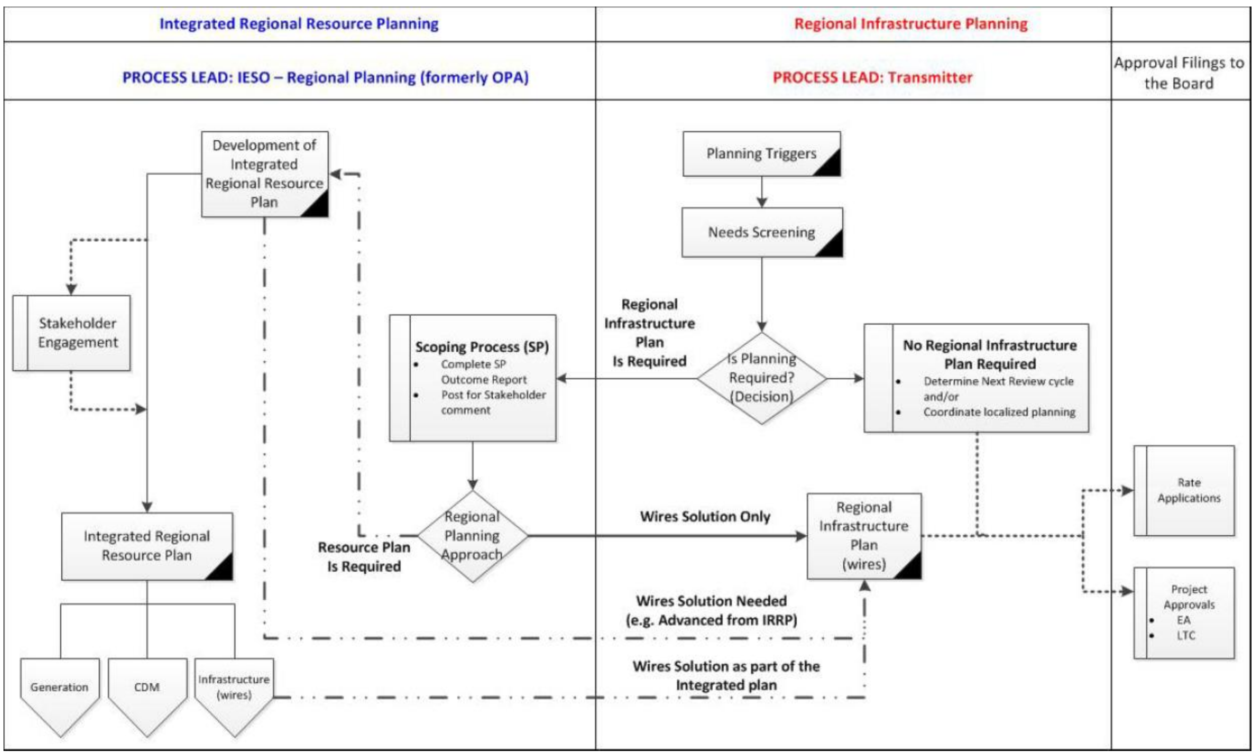


Regional Planning is a continuous process that was established by a working group, which issued a report that was endorsed by the OEB in May 2013. It is implemented in 21 electricity regions across Ontario, which have been identified based on electrical infrastructure boundaries. The process established in that report, which is depicted in Figure 5.2.2 - 2, has generally endured and consists of four main steps:

[15] Appendix H02 - Barrie / Innisfil Sub-Region IRRP Page 12

1. Needs Assessment (“NA”)
2. Scoping Assessment (“SA”)
3. Integrated Regional Resource Plan Development; and
4. Regional Infrastructure Plan (“RIP”) Development.

Figure 5.2.2 - 2: Regional Planning Process Flowchart[16]



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 working group (comprised of the IESO, Hydro One, and LDCs within the region under review) looks at changes in demand in a given area and performs an initial screen to identify needs in the region or sub-region using data from the IESO and the LDCs. The assessment may show that no action is needed, or that the LDCs and transmitter can coordinate a solution, such as a facility upgrade, on their own. Alternatively, the

[16] Appendix H10 - GTA West -RIP Page 17

assessment may show that there are needs that require coordination at the regional or sub-regional level, in which case the process moves to the SA stage.

In the SA stage, led by the IESO in consultation with the transmitter and LDCs, the working group reviews the information collected during the NA phase, along with additional information on potential non-wires alternatives, and decides on the most appropriate regional planning approach. If there is the potential to integrate a mix of different options, such as conservation, generation, distribution or new technologies, an IRRP will be recommended. If needs can be met through focusing only on wires, meaning additions or improvements to transmission lines or infrastructure, a RIP led by the transmitter will be recommended. A third option includes the relevant LDC and the transmitter working together to plan necessary local infrastructure investments. The recommendations are published in a SA Outcome Report, which is made available for public comment as part of a community engagement process.

If an IRRP is the required approach, a working group comprised of the IESO, the transmitter and the relevant LDCs will work together to 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;
- distributed generation;
- large-scale generation;
- transmission;
- distribution; and
- innovative solutions, such as Distributed Energy Resources, which can include renewable generation, energy storage, combined heat and power, and microgrids.

An integrated plan also considers options in terms of their feasibility, cost, reliability, government policy directives (such as the Conservation First initiative and Long-Term Energy Plan), environmental performance, and community preferences.

Community and stakeholder engagement continue throughout the IRRP phase. When needed, the process to establish a LAC will begin. 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 the required approach, 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 will confirm the LDCs and other agencies that need to participate in the planning study(s). The RIP will outline the scope of the study, describe planning assumptions, confirm needs and explain the rationale for the wires-only solutions recommended.

Final IRRPs and RIPs are posted on the IESO's and the relevant transmitter websites, and can be used as supporting evidence in a rate hearing for specific infrastructure investments.

5.2.2.8 ALECTRA UTILITIES' REGIONAL PLANNING ACTIVITIES

Alectra Utilities has participated in Regional Planning processes for the seven regions (including applicable sub-regions) that are included in its service territory. Each of these processes, along with the implications of those processes for Alectra Utilities' DSP and capital investment plan, is discussed below. In total, Alectra Utilities is planning to make investments relating to 4 projects in three of the regions/sub-regions (York, GTA West and Greater Hamilton) as a result of its involvement in these Regional Planning processes. Copies of the plans resulting from each of these processes, which are referenced in the discussion, are included in Appendix H - Regional Planning Reports. 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;
   - B.2 GTA North Western Sub Region

C. GTA West
   - C.1 Northern Sub Region
   - C.2 Southern Sub Region

D. Toronto Region

E. Burlington-Nanticoke
   - E.1 Greater Hamilton Sub Region

F. Niagara; and

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.

In 2014, an NA was carried out by Hydro One for the South Georgian Bay/Muskoka region. The report identified several needs that required regional coordination and recommended that the IESO lead the SA process. The working group comprised of staff from IESO, Hydro One and the local distribution companies (Hydro One Distribution, InnPower, Lakeland Power, Midland PUC, NewMarket-Tay, Orangeville Hydro, Orillia Power, PowerStream (now part of Alectra Utilities) Veridian connection, Wasaga Distribution) participated in the SA process. The working group 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 area falls within the Barrie/Innisfil sub-region and Parry Sound/Muskoka sub- region, respectively.

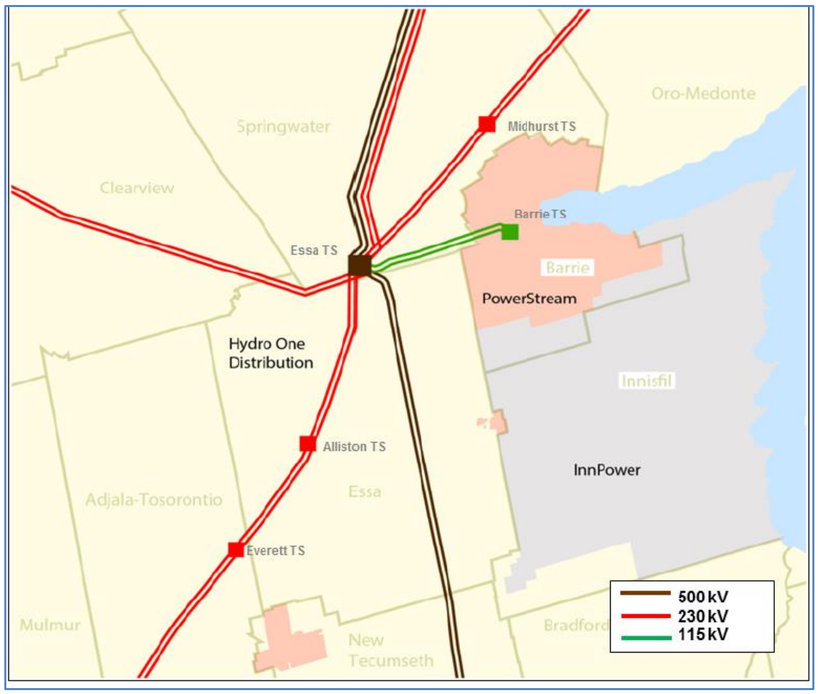
In June 2015, the South Georgian Bay/Muskoka SA Outcome Report was issued, a copy of which can be found in Appendix H01 - South Georgian Bay / Muskoka Region Scoping Assessment Outcome.

A.1 Barrie-Innisfil Sub Region

A map of the sub-region is provided in Figure 5.2.2 - 3. The process to develop the Barrie/Innisfil IRRP was initiated in 2015. A subsequent SA Report produced by the IESO recommended that the needs identified for the Barrie/Innisfil Sub-region should be further pursued, due to the potential for coordinated solutions and significant assets reaching end-of-life.

Hydro One Transmission identified existing sustainment initiatives at Barrie TS driven by the 115/44 kV station transformers reaching end-of-life, along with the 44kV switchgear, circuit breakers, disconnect switches and other station equipment. Barrie TS was placed in-service in 1962. The 44 kV switchyard assets at Barrie TS have been identified by Hydro One as being in need of replacement in the near term. Barrie TS is currently supplied by the 230/115 kV autotransformers at Essa TS, via the Essa 115 kV switchyard and 115 kV circuits E3/4B. These assets were built in the 1950s, with many of them already exceeding their expected life and in need of replacement in the near and medium term.

Figure 5.2.2 - 3: Map of Barrie/Innisfil sub-region[17]



The timing and replacement options for Barrie TS were discussed with the IRRP Working Group members. It was agreed based on the existing and forecasted station demand, that Barrie TS and E3/4B should be rebuilt to 230 kV, with 75/125 Mega Volt Amp (“MVA”) 44/230 kV transformers. This would add approximately 56 MVA of incremental supply capacity in the south Barrie and Innisfil area. Additional information on the IRRP outcomes can be found in Appendix H02 - Barrie / Innisfil Sub-Region IRRP and H03 - Barrie / Innisfil Sub-Region IRRP– Appendices.

Currently, all seven existing 44 kV feeder positions available at Barrie TS have been allocated. Six of the feeders are used to supply Alectra Utilities and one supplies InnPower. Based on the load projection it has been determined that additional capacity will be required for InnPower by 2020. The up-rated Barrie TS will have a total of eight feeder positions, meaning there will be an additional position available as an option to supply future load growth in both south Barrie and Innisfil.

[17] Appendix H02 - Barrie / Innisfil Sub-Region IRRP Page 12

Effective January 1, 2010, the City of Barrie annexed approximately 5,700 acres of land from the Town of Innisfil to accommodate its forecast growth. These annexed lands are within InnPower's service area supplied by Barrie TS and their development contributes to a large portion of the station's forecast growth. Barrie TS growth is also influenced by the recent and continued development of data centres in the City of Barrie, and forecast growth in the Town of Innisfil, including the proposed industrial and commercial development of Innisfil Heights near Highway 400.

Figure 5.2.2 - 4 shows the forecasted areas of concentrated growth in the Barrie/Innisfil area. Figure 5.2.2 - 5 shows the range of electricity demand for various forecast scenarios provided in the 2015 IRRP. The region will continue to grow and even with upgrading the Barrie TS in 2020 the needs assessment indicated that the transformation capacity will be exceeded in 2022.

Figure 5.2.2 - 4: Forecasted Areas of Concentrated Growth

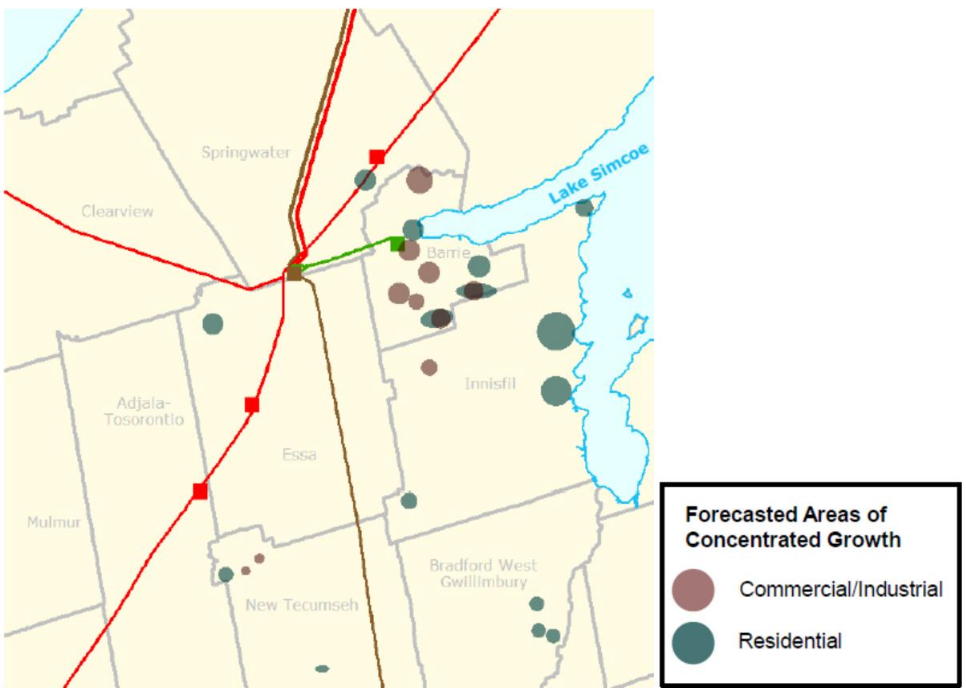
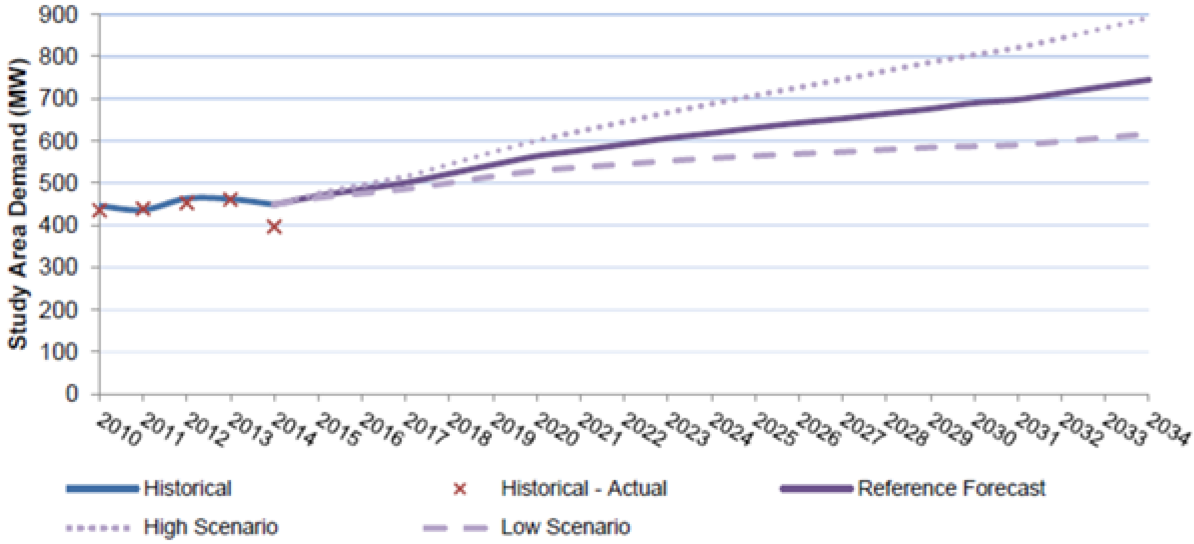


Figure 5.2.2 - 5: Barrie/Innisfil High and Low Demand Forecast Scenarios[18]

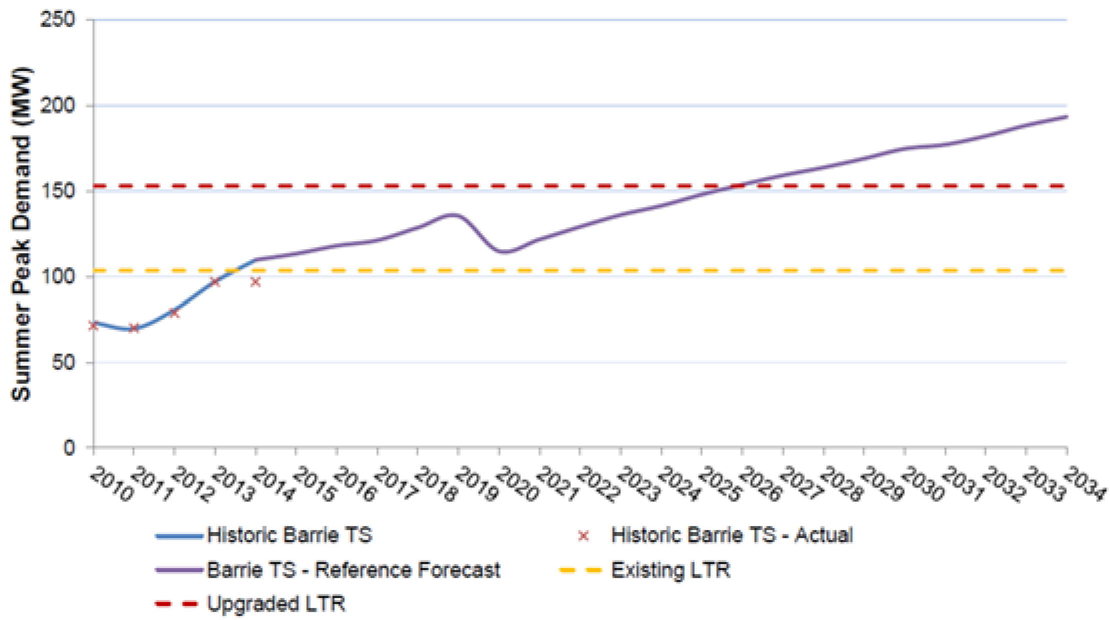


Due to the proximity of Barrie TS to the Midhurst TS, and because Alectra Utilities has an existing supply from both stations, load transfer is a feasible option to relieve Barrie TS. Alectra Utilities has a distribution project to construct 2 -44kV feeders from Midhurst TS to supply South Barrie area. Upon completion of the additional supply feeders from Midhurst TS, Alectra Utilities could transfer up to 27 MW of load from Barrie TS. This available load transfer capacity is based upon normal operating conditions. During feeder outage situations, the transfer amount may vary based on the redundancy needs of key customers.

This load transfer will enable Alectra Utilities to defer the capacity need at the upgraded Barrie TS from 2022 to 2026 as well as allow Alectra Utilities to transfer load between Barrie TS and Midhurst TS during emergency conditions. Figure 5.2.2 - 6 shows the demand forecast project in 2015 IRRP for Barrie TS accounting for Alectra Utilities' load transfer.

[18] Appendix H02 - Barrie / Innisfil Sub-Region IRRP Page 27

Figure 5.2.2 - 6: Barrie/Innisfil Demand Forecast Scenarios (high and Low)[19]



Based on the IRRP and consistent with the *Places to Grow Act*, the Barrie/Innisfil Sub-region's electricity system is expected to reach its capacity sometime between 2026 and 2035. Therefore, as early as 2026, additional transformer station capacity will be required, particularly for the south Barrie and Innisfil areas.

The Barrie/Innisfil Working Group issued a hand-off letter in December 2015 to request that Hydro One begin development work on the Barrie TS upgrade.

In early 2018, Hydro One provided Alectra Utilities with station layout drawings for the uprate of Barrie TS, which indicated the breaker lineup for feeder integration. As per the plan, the new station will be constructed west of the existing station. Hydro One will also move the station egress westward and include an additional feeder for InnPower. The feeder egress relocation and additional feeder will require integration reconfiguration for the six Alectra Utilities feeders emanating from the station. Alectra Utilities will need to relocate the existing feeders, 13M3 to 13M8, to match with the breaker lineup of the new station, while ensuring that there are no conflicts with the InnPower circuits. An additional conflict with Alectra Utilities' 23M24 Midhurst

[19] Appendix H02 - Barrie / Innisfil Sub-Region IRRP Page 42

TS feeder, which is currently routed along the west side of the Barrie TS property, has also been identified and will require relocation.

In addition, Alectra Utilities is responsible for the installation of revenue metering equipment at Barrie TS, as per Schedule 4 of the Hydro One Customer Wholesale Revenue Metering Agreement and Chapter 6 of the IESO Market Rules. The existing Barrie TS utilizes bus metering. Hydro One has presented Alectra Utilities with the option to either contribute 100% of the capital cost towards the bus metering, or utilize Alectra Utilities-owned Primary Metering Enclosures ("PME"). Alectra Utilities has noted accessibility issues with the existing station bus metering at Barrie TS. In addition the bus metering is a more expensive solution than feeder metering. As such, Alectra Utilties will be installing feeder metering.

Alectra Utilities has planned for Barrie TS feeder integration for 13M3 through to 13M8, as well as the relocation of 23M24 to be completed in 2021.

A.1.1 Upcoming RIP update

Another regional planning cycle will be underway in 2019 for the Barrie Innisfil region, starting with the NA in first quarter of 2019.

In 2018, Alectra Utilities and InnPower, with support from the IESO's conservation fund, commenced a Local Achievable Potential ("LAP") study for the Barrie TS service area. The objective is to determine demand savings potential through conservation and demand management for the Barrie TS area, above and beyond what is attributed to the Long-Term Energy Plan ("LTEP"). The study will also help determine options for acquiring this potential (e.g., incentives and adders to existing CDM programs, new programs, behind-the-meter generation, energy storage, etc.). In addition, the study will provide a better understanding of the costs and feasibility of conservation and demand management measures to address capacity needs in the area to better inform options for the upcoming planning cycle.

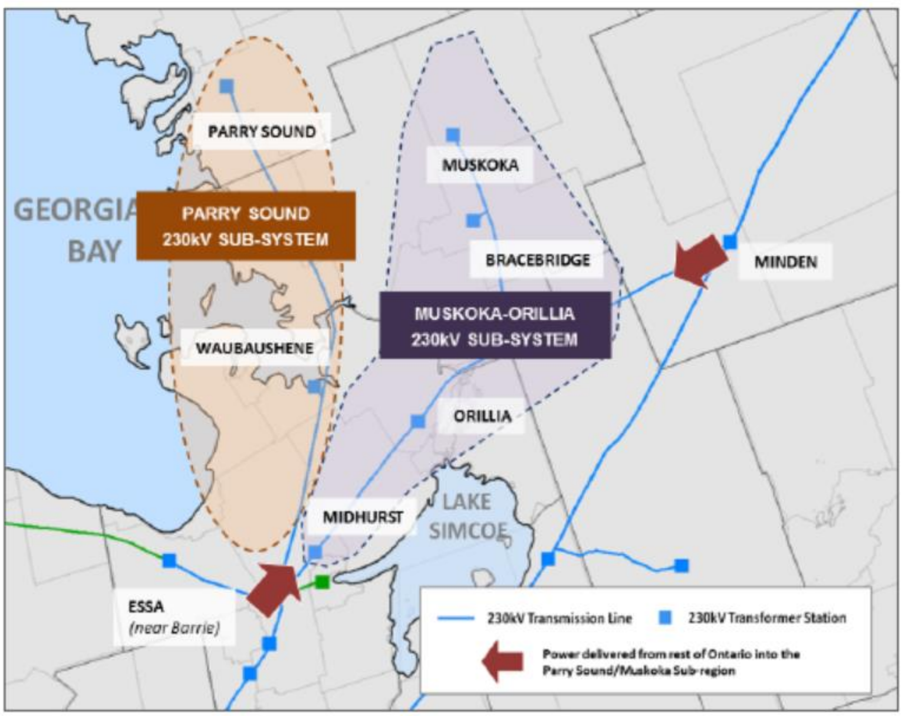
The following investments are planned for the Barrie Innisfil region:

1) Design and construct Barrie TS feeder integration for 13M3 through to 13M8, as well as relocate the Midhurst 23M24 feeder currently located on the west side of the station.
2) Install primary metering unit on six feeders (13M3 through to 13M8) and invest in feeder metering.

A.2 Parry Sound/Muskoka Sub Region

In 2015, an IRRP for the Parry Sound/Muskoka subregion was initiated. The 2015 Parry Sound /Muskoka working group include the staff from IESO, HONI (Transmission) and the local distribution utilities serving the area (HONI Distribution, Lakeland Power, Midland PUC, New Market-Tay Power, Orillia Power, PowerStream (now part of Alectra Utilities), Veridian Connections). Alectra Utilities' service territory (Penetanguishene) falls within the Parry Sound/Muskoka sub region and is supplied by Waubashene TS. Midhurst TS is also included in the Parry Sound/Muskoka IRRP since it is supplied by the Muskoka-Orillia 230kV sub-system. Please refer to H04 - Parry Sound / Muskoka Sub-Region IRRP and H05 - Parry Sound / Muskoka Sub-Region IRRP Appendices. Refer to Figure 5.2.2 - 7 for a map of the transmission systems in this region.

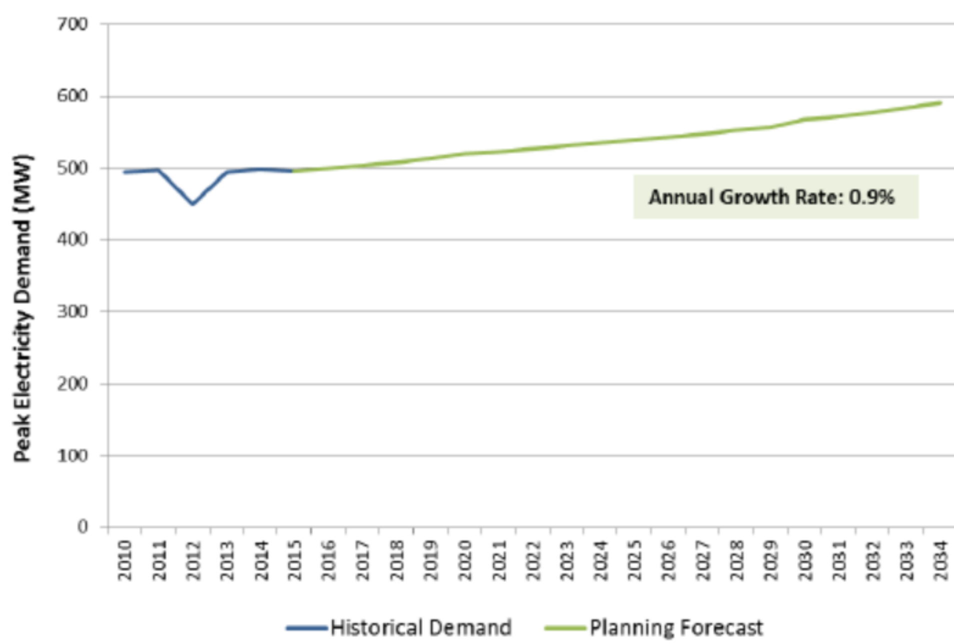
Figure 5.2.2 - 7: Parry Sound/Muskoka Transmission System (230kV)[20]



[20] Appendix H04 - Parry Sound / Muskoka Sub-Region IRRP Page 18

Over the 20 year period from 2015-2035, this subregion is forecast to experience a modest increase in electricity demand as shown in Figure 5.2.2 - 8. Slower growth is expected in this subregion's manufacturing sector but this will likely be offset by growing indigenous communities, as well as by new residential and commercial developments. Electric space and water heating requirements from communities, as well as new residential and commercial developments, will continue to be a major driver of peak electricity demand.

Figure 5.2.2 - 8: Parry Sound/Muskoka Sub-Region Planning Forecast (2015-2034)[21]



In order to support forecast demand growth, the electricity system will need to have sufficient capacity. Over the longer term, it was projected that the electricity demand growth could also exceed the supply capability of the Muskoka-Orillia 230 kV sub-system. In particular, Waubaushene TS can supply up to 99 MW of local peak, and as of 2015 peak demand was 96MW. In addition, the transformers at this station were found to be nearing capacity, with a risk that electricity demand growth could exceed capability by 2019. On this basis, action was considered to be needed in the near term to ensure that the electricity system has adequate

[21] Source- Appendix H04 - Parry Sound / Muskoka Sub-Region IRRP Page 26

supply to support future growth. These needs will be revisited in the next iteration of the IRRP for this subregion.

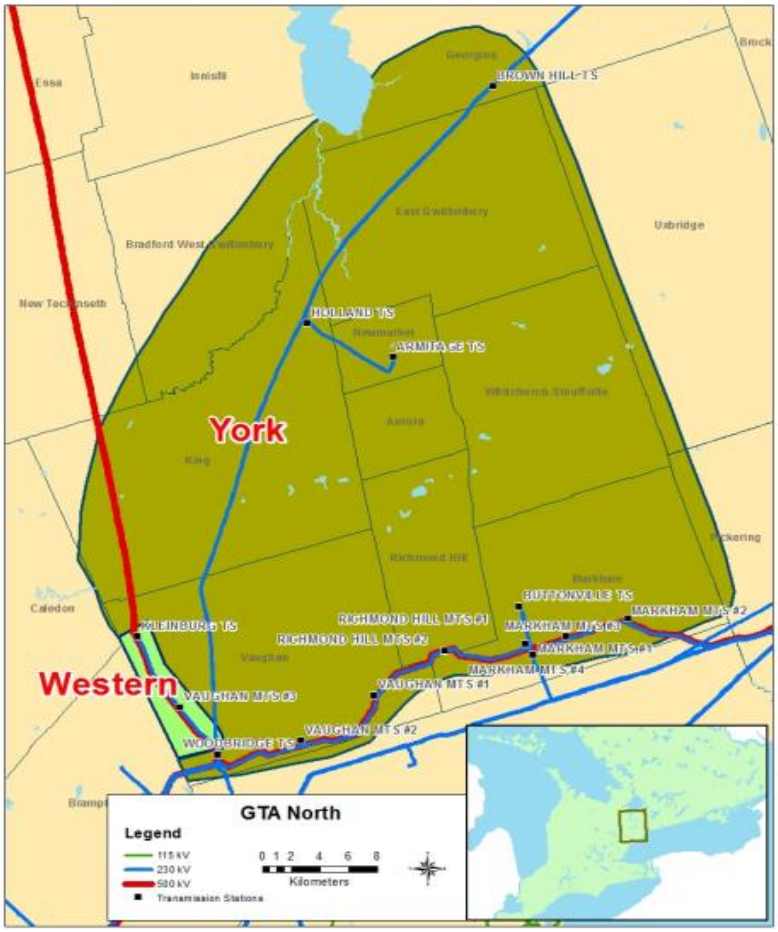
Until those investments are planned and made through the next iteration of the IRRP process, about 4 MW of the area's nearer-term demand growth on Waubaushene TS can be supplied from Orillia TS using the existing 44 kV sub-transmission infrastructure. If required, another 7 MW at Waubaushene TS can be supplied from Midhurst TS upon completion of Barrie Area Transmission Reinforcement in the early 2020s. This option would use only the existing distribution system with no new facilities being required, thereby requiring minimal cost and making better use of current infrastructure. Please see Appendix H02 - Barrie / Innisfil Sub-Region IRRP.

B GTA North

As shown in Figure 5.2.2 - 9, the GTA North Region approximately follows the boundaries of the Regional Municipality of York, and also includes parts of the City of Toronto, Brampton and Mississauga. Figure 5.2.2 - 10 illustrates the GTA North transmission system. The region is divided into two sub-regions:

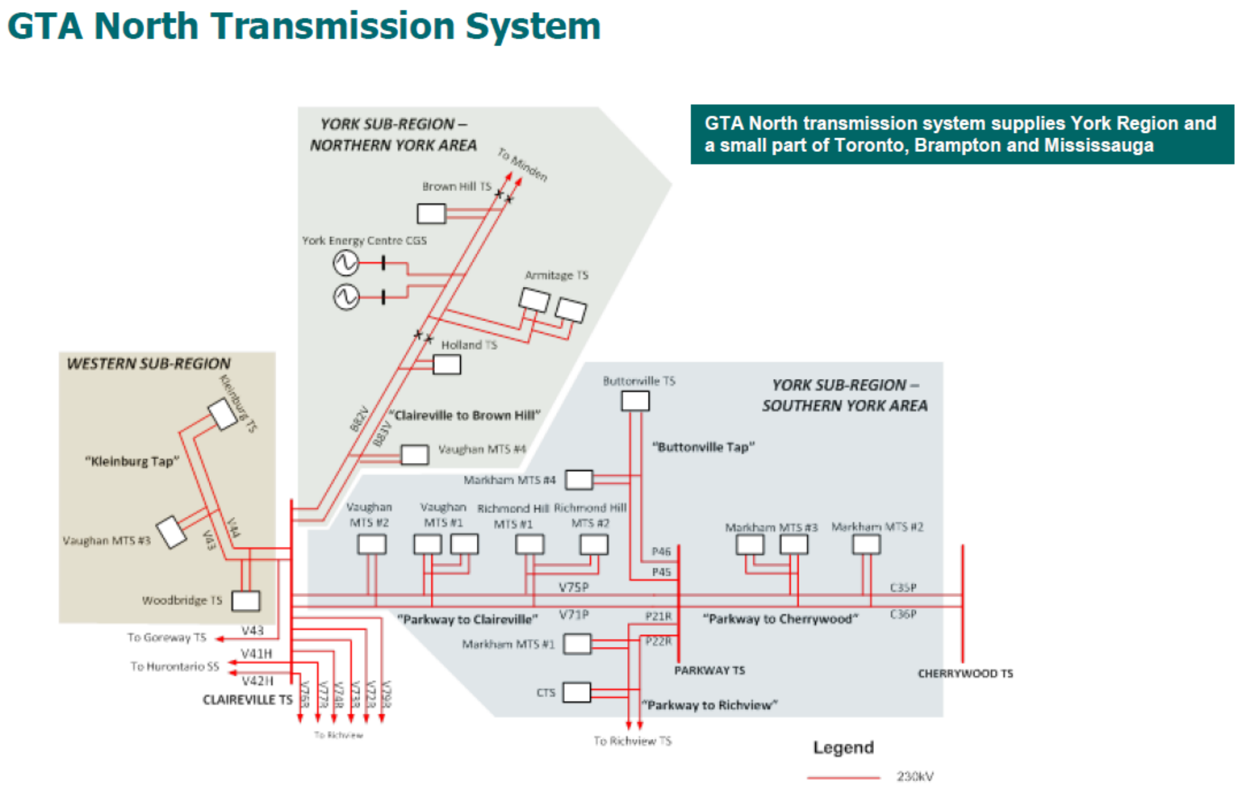
- York Sub-Region
    - This area includes Southern York area (the Municipalities of Vaughan, Markham, and Richmond Hill) and Northern York area (the Municipalities of Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville, Georgina, and some parts of Durham and Simcoe regions are supplied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

Figure 5.2.2 - 9: GTA North Supply Area[22]



22 Appendix H06 - GTA North Region Needs Assessment Page 9

Figure 5.2.2 - 10: GTA North Transmission System[23]



The first GTA North RIP was completed in February 2016. It followed the completion of the York Sub-Region IRRP by the IESO in April 2015 and the Western Sub-Region NA Study by Hydro One in June 2014.

Participants in this RIP included the IESO, Alectra Utilities, HONI (Distribution), New Market-Tay Power and Toronto Hydro

Hydro One launched a new GTA North regional planning cycle in December 2017, starting with a NA update. A copy of the NA Report for the GTA North Region, which was finalized on March 22, 2018, is provided in Appendix H06 - GTA North Region Needs Assessment. The updated NA Report reaffirmed the previously identified needs, and identified certain additional needs, as set out in Table 5.2.2 -1 below.

[23] Appendix H06 - GTA North Region Needs Assessment Page 10

Table 5.2.2 - 1: GTA North Needs[24]

No	Needs Identified in Previous RIP and IRRP
1	Load Restoration – V43+V44 (“Kleinburg Tap”)
2	Load Security on V71P/V75P – Parkway to Claireville
3	Vaughan Transformation Capacity
4	Markham Transformation Capacity
5	Station Service Supply to York Energy Centre (YEC)
6	Northern York Area Transformation Capacity
	New Needs
1	End-of-Life Equipment* – Woodbridge TS T5 transformer
2	Load Restoration – P45+P46 (“Buttonville Tap”)

**-End of Life as defined by HONI*

The working group recommendations to address the identified needs arising from the updated NA are as follows:

1. Further regional coordination is not required to address the End-of-Life (EOL) Woodbridge TS T5 transformer. Instead, this need should be addressed by Hydro One and affected LDCs, which should coordinate the replacement plan. Hydro One is to keep the group informed of the status of the plan and if any major changes occur.
2. As per the IESO’s letter of support in April 2017, Alectra Utilities and Hydro One are to continue developing a new 230/27.6kV TS in the Markham-Richmond Hill area. Please refer to the discussion of the York Sub-Region in section 2.1, below, for more information.
3. Further assessment and regional coordination is required in the IRRP and/or RIP to develop a preferred plan for the following needs:
   - Load Restoration – P45+P46 and V43+V44Load Security on V71P/V75P – Parkway to Claireville
   - Vaughan Transformation Capacity
   - Station service supply to York Energy Centre
   - Northern York Area Transformation Capacity

[24] Appendix H06 - GTA North Region Needs Assessment Page 11

B.1 York Sub-Region

The York Sub-Region IRRP completed in 2015 addressed the electricity needs of the York Sub-Region over the 20 year period commencing in 2015, at which time the IRRP report was completed by the IESO on behalf of a technical Working Group that included Newmarket-Tay Power, PowerStream, Hydro One Distribution and Hydro One Transmission.

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. Extensive urbanization has resulted in electricity demand growth greater than the provincial average. With a current population of over 1 million, York Sub-Region's electricity infrastructure currently supplies almost 2,000 megawatts (MW) of demand. Under the province's *Places to Grow* policy, York Region is expected to host substantial continued population growth in the coming decades. This growth requires a strong need for integrated regional electricity planning to ensure that the electricity system can support the pace of development over the long term.

The York Sub-Region IRRP identified investments for immediate implementation to meet near-term needs, as well as options to meet medium- and longer-term need. However, given forecast uncertainty, the longer development lead time and the potential for technological change, the plan maintains flexibility for longer-term options and does not recommend specific projects. Instead, the long-term plan identifies near-term actions to develop alternatives and engage with the community, to gather information and lay the groundwork for future options. Those actions were intended to be completed before the next IRRP cycle, which is expected to commence in 2019.

The IRRP report and Appendices are provided in Appendix H07 - York Region IRRP and H08 - York Region IRRP Appendicies.

The status of the 2015 York Sub-Region recommendations is listed below:

- *Implement Conservation and Distributed Generation*. Meeting provincial conservation targets established in the 2013 LTEP is at the core of York Sub-Region's near-term plan. Consistent with the province's Conservation First policy, conservation is targeted for approximately 170 MW, or 32% of forecast demand growth, during the first 10 years of the study. Monitoring success, which includes evaluating, measuring and verifying peak demand savings, is an important element of the near-term plan. It will lay the foundation for the long-term plan by enabling the performance of specific conservation measures in the Sub-Region.

- *Vaughan Transformation Capacity*. Alectra Utilities built a new station, "Vaughan Municipal Transformer Station (TS) #4" which was energized in 2017.
- *Switching Facilities at the Holland Station Site*. The switches were added, with all work completed in 2017.
- *Install In-Line Circuit Switchers on Parkway 230 kV Transmission Line*. The circuit switchers were installed, with all work completed in 2018.
- *Initiate an infrastructure project for addressing electricity needs in Markham-Richmond Hill*. Based on municipal growth projections, and consistent with the province's Places to Grow Act, 2005, the electricity system in the Markham and Richmond Hill area within the York Sub-Region is expected to reach its capacity by 2026. The transmission system supplying these stations is also expected to reach its limits by 2030. Planning to address the station capacity needs must be coordinated with the plan to address the long-term transmission system needs, as they are interrelated. To address electricity needs in the Markham-Richmond Hill area, the IESO, on behalf of the Working Group, recommended proceeding with a project consisting of:
    - A new 230/27.6kV DESN transformer station in the northwestern part of Markham (Markham TS#5)
    - Distribution and/or transmission lines to connect the new transformer station

In early 2017, a hand off letter was sent by the IESO to Alectra Utilities and Hydro One Transmission to proceed with the work leading to the implementation of this project including pursuing the required environmental and regulatory approvals. Details related to the choice of location for the new transformer station and routing of the distribution feeders and transmission lines will be addressed as part of the project development process, and will include opportunities for the public to provide input. Considering the typical development timelines for such projects and the load growth forecast, it was initially recommended by the IESO that Alectra Utilities and Hydro One Transmission complete all work by 2023.

Based on the latest load forecast and CDM impact, the targeted completion date has been revised to 2026. The timelines includes completing the Class Environmental Assessment (EA) in 2023/ 2024 so that the design can begin in 2025.

Another regional planning cycle is underway for York Sub-Region, with the next iteration of the IRRP anticipated to be completed and posted in fourth quarter of 2019.

A SA Outcome Report and Terms of Reference for the GTA North (York Region) IRRP was finalized and posted in August 2018, following a two-week comment period. The SA outcome report is provided in Appendix H09 - York Region Scoping Assessment Outcome.

Alectra Utilities will complete the class EA for the new Transformer Station in Markham in 2023 and 2024.

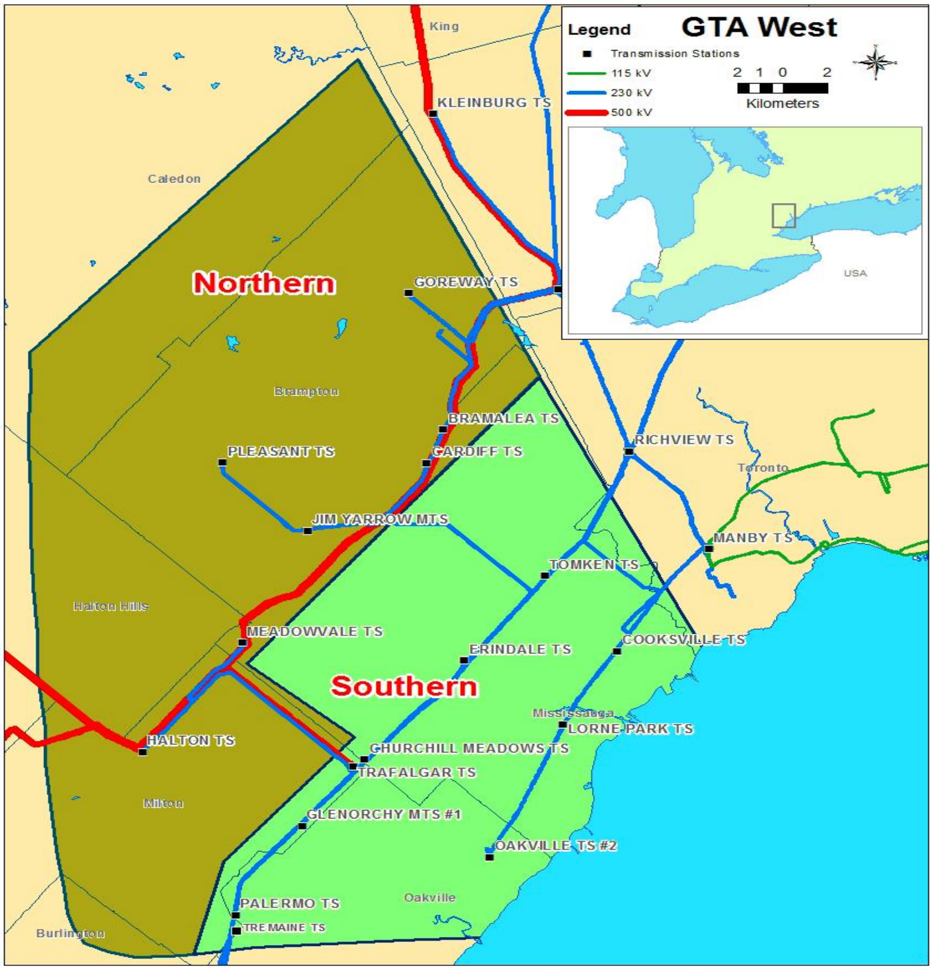
B.2 GTA North Western Sub Region

This sub region comprises of the western portion of municipality of Vaughan. Electrical supply to this sub region is provided through Clairville TS and 230 kV Klienburg tap; which supplies three 230kV Transformer Stations (Woodbridge TS, Vaughan TS 3 and Klienburg TS). The needs of the GTA North Western sub-region were addressed as part of the planning process for the sub-region of the GTA West Region (see section C.2).

C GTA West

The Greater Toronto Area (“GTA”) West Region includes Halton, Peel, 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 (Brampton) as well as the Southern Sub-region (Mississauga), as shown in Figure 5.2.2 - 11.

Figure 5.2.2 - 11: GTA West Region[25]



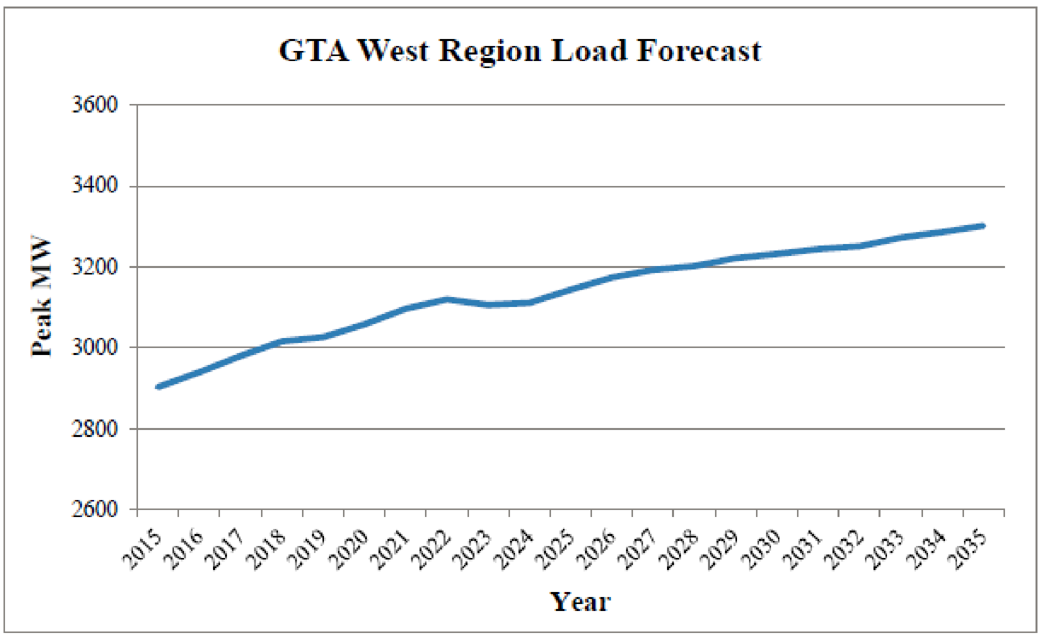
Bulk electricity in the region is supplied by the Burlington TS from the west, the Claireville TS from the north, the Richview TS and Manby TS from the east, and 500/230 kV autotransformers at the Trafalgar TS, and distributed by a network of 230 kV transmission lines and 17 transformer stations. Local generation in the region includes two gas fired plants, Sithe Goreway CGS (839 MW rated capacity) and TCE Halton Hills CGS (683 MW rated capacity).The RIP, which was finalized in January 2016 by the working group comprised of staff from the IESO, HONI (Transmission), Burlington Hydro, Halton Hill Hydro, Enersource Hydro and Hydro One Brampton (now part of Alectra Utilities), HONI (Distribution), Milton Hydro and Oakville Hydro provides a

[25] Appendix H10 - GTA West RIP Page 13

consolidated summary of the needs and recommended solutions for both the Northern Sub-Region and Southern Sub-Region that make up the GTA West Region. The RIP report is provided in Appendix H10 - GTA West RIP.

Figure 5.2.2 - 12 shows the GTA West Region load forecast from 2016 to 2035 from the RIP report. The forecast represents the sum of the load for the 17 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 2900 MW in 2015 to 3300 MW in 2035.

Figure 5.2.2 - 12: GTA West Region load forecast from 2016 to 2035[26]



The major infrastructure investments planned for the GTA West Region over the near-term and medium-term (2016-2025), as identified in the RIP, are listed in Table 5.2.2 - 2, below.

Table 5.2.2 - 2: GTA West Needs[27]

Project
Build new Halton Hills Hydro MTS
Build new Halton TS #2
Build new 44/27.6 kV DS to relieve Erindale TS T1/T2
Upgrade (reconductor) circuits H29/H30

[26] Appendix H10 - GTA West -RIP Page 23
[27] Appendix H10 - GTA West RIP Page 7

Out of the above stated needs, Alectra Utilities' predecessor, Enersource, was only responsible for building a new 44/27.6 kV distribution station to relieve Erindale TS. The other needs were the responsibility of other LDC's in the regional planning area and Hydro One. Additional details on the new DS to relieve Erindale TS project are included in section 3.1.

A second cycle of Regional Planning for the GTA West region is now underway, with the NA process starting in first quarter of 2019.

C.1 GTA West Southern Sub Region

GTA West's Southern Sub-Region covers the area that is south of Highway 407 and which is supplied by 230 kV circuits out of Trafalgar TS, Richview TS and Manby TS. The area is served by total of nine 230/44 kV or 230/27.6 kV Transformer Stations. Alectra Utilities and Oakville Hydro are the main LDCs serving this sub region. The region's SA and NA reports were published in May 2014 and September 2014, and determined no further regional planning (RIP or IRRP) was required. The NA and SA report are provided in Appendix H11 - GTA West Southern Sub-Region Scoping Assessment Outcome and H12 - GTA West Southern Sub-Region Needs Assessment.

The SA report noted that the existing Erindale TS (T1/T2) DESN load exceeded the normal supply capacity. However, there was extra capacity available in the area's 44 kV system that was able to be utilized by building a step down (44/27.6 kV) distribution station.

Options for providing the required relief were investigated and a report entitled "Erindale TS T1/T2 DESN Capacity Relief" was completed in July of 2015. The report, a copy of which is provided in Appendix H13 - GTA West Southern Sub-Region Local Planning, noted that Hydro One, and Alectra Utilities' predecessor Enersource, agreed that the Erindale capacity relief was primarily a distribution planning issue and would be resolved through LDC distribution planning.

This Erindale capacity relief planning was indicated in the Enersource Rate Zone DSP filed on July 7, 2017, by Alectra Utilities in EB-2017-0024. In that plan, the construction of a new Britannia MS was proposed. However, as a result of the consolidations underlying the formation of Alectra Utilities, other options have become available that avoid the need for construction of this station, as follows.

Mini-Orlando MS was completed in June 2017 and served to shed 13MW of load from the 27.6kV system during the 2017 summer peak once connected to the 44kV system. The station comprises twin 20MW ONAN[28] transformers and can provide 66MW ONAF[1] capacity during contingency conditions. Alectra Utilities plans to load Mini-Orlando to 40MW and thus shed another 27MW of load from the existing 27.6kV system during normal operating conditions. In addition, the Jim Yarrow TS, which was formerly owned and operated by Alectra Utilities' predecessor Hydro One Brampton, has additional capacity that can be utilized to offset the needs in Mississauga without the need to build a new Britannia TS 44/27.6kV station. In addition to mitigating the need for new station construction, this option is technically superior as it eliminates transformation losses (44/27.6kV). It is also significantly lower in cost as it involves building an additional feeder rather than a new station plus associated feeders.

In order to implement the solution described above, Alectra Utilities is currently designing a link between Mississauga and Brampton on Mavis Rd. as part of Project 150357. The 25M9 is a lightly loaded 27.6kV feeder from Jim Yarrow TS in Brampton that will be able to provide up to 25 MW of capacity in order to offload Erindale TS. Infrastructure is already established on Mavis Rd and a highway crossing is in place from Brampton. The cost for this alternative is $2.13MM, as compared to the cost for buying the land and building a new 44/27.6 kV station, which would have cost approximately $7.5MM, not including the cost of the feeders.

C.2 GTA West Northern Sub-Region

This sub-region, which covers the area north of Highway 407, includes the municipalities of Brampton, Milton, Halton and the southern portion of Caledon. A map of the sub-region is provided in Figure 5.2.2 - 13.

Supply to this sub-region is provided by 230 kV circuits through seven 230/44 kV or 230/27.6kV step down transformer stations, and includes local generation consisting of the Sithe Goreway

[28] The contingency rating is determined by the cooling capabilities of the transformer and is equivalent to the highest cooling rating; i.e. Oil Natural Air Natural (ONAN) (100% of base rating) for self-cooled transformer units, Oil Natural Air Forced (ONAF) (133% base rating) or ONAF/ONAF (166% of base rating) for transformer units with single and dual stage fans. The ONAN rating is the normal rating of the transformer without additional cooling, while the ONAF rating is the maximum permissible loading on the transformer before loss of life.

GS in Brampton and the TransCanada Halton Hills GS located in Halton Hills. Alectra Utilities, Milton Hydro and Halton Hills Hydro are the sub-region's three main LDC's.

The planning process leading to the development of the IRRP began in 2013, following 10 years of substantial demand growth and expanding urban boundaries. It was recognized in the IRRP that the limited existing electrical infrastructure in the area has to be addressed and that this should be coordinated with ongoing bulk system planning.

Although the Kleinburg radial pocket is located within the GTA North Region, it was included within the scope of the GTA West Northern sub-region IRRP as the electrical demand growth in this pocket is driven largely by new customers in southern Caledon, in particular the Town of Bolton. In addition, the Northwest GTA sub-region is characterized by a large number of similarly configured radial pockets, meaning that restoration needs would be a common issue to be addressed across the entire planning area.

Figure 5.2.2 - 13: GTA West Northern Sub Region[29]

Load forecasts were completed for the two scenarios “Expected Growth” and “High Growth”. Under the Expected Growth forecast scenario, electricity demand growth was projected at 1.68% per year in the near and medium term (first decade), and 0.82% per year for the second decade. For the High Growth Forecast scenario, electricity demand growth was projected at 2.06% per year for the first decade, but dropping to an average of 1.18% per year for the second decade. Over the 20-year planning period, the Expected and High Growth forecasts averaged 1.3% and 1.7% per year, respectively.

The Pleasant TS, located in northern Brampton, supplies power to northwest Brampton, southwest Caledon and parts of Georgetown, and is a key source of supply for this sub-region. It has two 230/27.6 kV step-down transformers and one 230/44 kV transformer. The load forecast indicated that there is adequate capacity for the long term to handle growing electrical demand

[29] Appendix H14 - Northwest GTA IRRP Page 3

on the 27.6 kV system but this is not the case for the 44 kV system. Based on growth forecasts, an alternative supply may be required by 2033.

In addition to transformation capacity, the study identified overload issues and restoration issues on the 500 kV and some 230 kV transmission assets. In the long term, there is a need for transmission line capacity in Northern Brampton/Southern Caledon and Halton Hills to meet forecast demand growth.

The GTA West Northern Sub Region RIP was completed in April 28, 2015 and is provided in Appendix H14 - Northwest GTA IRRP.

D Toronto Region

The Toronto Region includes the area defined by the municipal boundary for the City of Toronto. For the regional planning cycle that was completed in 2016, the Toronto Region was divided into two sub-regions - Central Toronto and Northern Toronto. However, the current regional planning cycle, initiated in late 2017, proposes that there be no sub-regions. The working group consisted of staff from IESO, HONI (Transmission), Toronto Hydro, Alectra Utilities, Veridian Connection and HONI (Distribution).

Alectra Utilities is involved in the Toronto Region SA because several distribution feeders from stations with this region supply Mississauga, Markham and Vaughan, as shown in Table 5.2.2 - 3.

Table 5.2.2 - 3: Toronto Region Feeders supplying Alectra Utilities

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

As none of the needs identified in the current Toronto Region RIP directly impact facilities supplying Alectra Utilities customers, it was agreed that for the current regional planning cycle the core Working Group will only include the IESO, Toronto Hydro and Hydro One Transmission.

The Toronto Region SA Outcome Report, published February 9, 2018, recommended an IRRP for this region. A copy is provided in Appendix H15 - Toronto Region Scoping Assessment Outcome.

E Burlington –Nanticoke Region

The Burlington-Nanticoke Region is divided for planning purposes into three sub-regions:

1. Brant
2. Bronte
3. Greater Hamilton

Alectra Utilities' service territory does not include any portions of the Brant or Bronte sub-regions, so it does not participate in planning for those areas. The working group consisting of staff from IESO, HONI (Transmission), Alectra Utilities, Brantford Power, Burlington Hydro, Veridian Connection and HONI (Distribution), Energy+ Inc and Oakville Hydro participated in developing the RIP report.

The RIP was published in early 2017 and is provided in Appendix H16 - Burlington to Nanticoke RIP.

E.1 Greater Hamilton Sub-Region

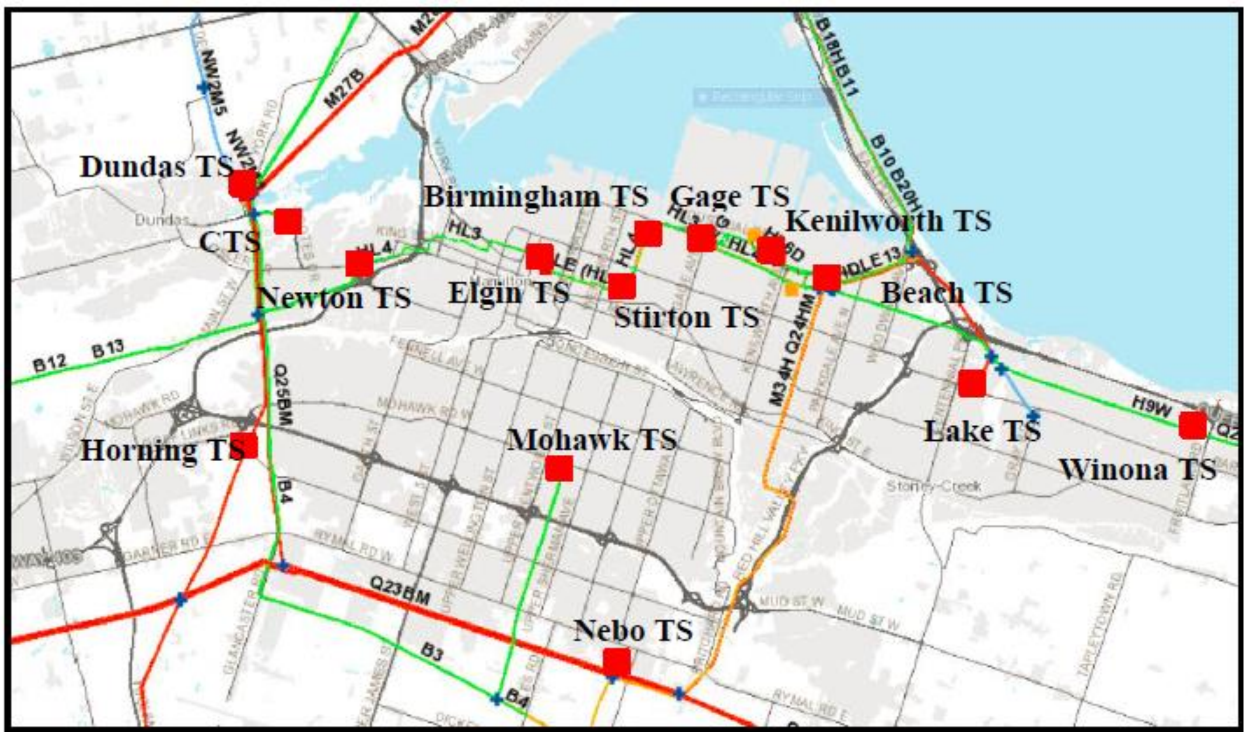
This sub-region encompasses the City of Hamilton, as well as the Townships of Flamborough and Glanbrook and the Towns of Dundas and Stoney Creek. A map of the sub-region is provided in Figure 5.2.2 - 14. Some of this sub–region's electrical infrastructure are among the province's oldest. Electricity supply to the sub-region is as follows:

- the Beach TS 115 kV area, which includes five 115 kV step down stations (Beach TS T3/T4 DESN, Birmingham TS, Kenilworth TS, Stirton TS and Winona TS) and a CTS supplied from the 230/115 kV autotransformers at Beach TS.
- the Burlington TS 115 kV area, which includes Dundas TS, Dundas #2 TS, Elgin TS, Gage TS, Mohawk TS, Newton TS and one customer owned CTS supplied from the 230/115 kV autotransformers at Burlington TS.

- a 230 kV area, which includes the Beach TS T5/T6 DESN, Horning TS, Nebo TS, Lake TS and two customer owned stations supplied from 230 kV circuits connecting into Beach TS and Burlington TS.

The RIP identified several end of life needs for the Hamilton sub-regionand recommended further assessment of mid- and long-term needs in this sub-region by conducting a NA, which was completed in Q2 2017, followed by a SA by the IESO. The SA was completed in Q3 of 2017 and recommended an IRRP. The IRRP for the Hamilton sub-region is currently underway and is expected to be completed in first quarter of 2019.

Figure 5.2.2 - 14: Greater Hamilton Sub Region[30]



The needs identified for the Hamilton Sub-Region, for the near-term (2016-2020) and the mid to long-term (beyond 2020,) per the RIP report, are provided below in Table 5.2.2 - 4 and Table 5.2.2 - 5, respectively, with planned and the current status.

[30] Appendix H16 - Burlington to Nanticoke RIP Page 21

Table 5.2.2 - 4: Greater Hamilton Sub Region Needs [31]

No.	Needs	Planned In service per RIP	Current Status
5	Kenilworth TS – Power Factor Correction	2021	2021
6	Kenilworth TS – EOL* transformers and switchgear	2018	2021
7	Beach TS – EOL* T3/T4 DESN Transformers	2019	2019
8	Gage TS – EOL* transformers and switchgear	2019	2021
13	Elgin TS – EOL* transformers and switchgears	2019	2020
14	Mohawk TS (T1/T2) – Station Capacity and EOL T1/T2 Transformers	2019	2019

Table 5.2.2 - 5: Mid and Long Term Needs [32],[33]

No.	Needs	Planned In service per RIP	Current Status
1	Birmingham TS EOL* Metalclad Switchgears	2021	2025
2	Dundas TS EOL* T1/T2 Switchgear	2021	2025
3	Newton TS EOL Transformers, Switchgears, Breakers	2021	2025
5	Lake TS EOL* Switchgear	2022	2025
6	Stirton TS EOL* Switchgear	2022	NA
7	Beach TS EOL T7/T8 Auto-transformers and T5/T6 Switchgear	2025	2027
8	EOL Cables in Hamilton area: H5K/H6K, K1G/K2G, HL3/HL4	NA	NA

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

For the projects listed above, Alectra Utilities has firm scopes and designs for the Kenilworth project and will be executing in 2020. In addition there are several other projects identified in

[31] Appendix H16 - Burlington to Nanticoke RIP Page 8
[32] At the time of the writing of DSP some dates for project implementation have not been identified by Regional Planning process.
[33] Appendix H16 - Burlington to Nanticoke RIP Page 9

Table 5.2.2 - 5 that have been identified in the RIP but which have not been included as the implementation dates have not been determined.

- **Station : Kenilworth TS**
  - HONI Scope – replace T3 transformer and replace EJ switchgear, remove and decommission T1 and T4 and DK bus. Reconfigure T2/T3 to supply B1Y1 and EJ busses.
  - Investments required – Relocate egress cables, new metering cabinets. (Not part of the HONI upgrade, but to be performed in conjunction with construction, is a capacitor bank installation required to correct power quality issues as identified in the regional planning process).
  - Timing - planned in-service is November of 2021. (T3 replacement is planned for the second quarter of 2019).

F Niagara Region

The Niagara Region includes the City of Port Colborne, City of Welland, City of Thorold, City of Niagara Falls, Town of Niagara-on-the-Lake, City of St. Catharines, Town of Fort Erie, Town of Lincoln, Township of West Lincoln, Town of Grimsby, Township of Wainfleet and the Town of Pehlam. Alectra Utilities' service territory includes the City of St. Catharines. A working group consisting of staff from IESO, HONI (Transmission), Alectra Utilities, Canadian Niagara Power, Niagara Peninsula Energy, Niagara-on-theLake Hydro, Veridian Connection and HONI (Distribution), Energy+ Inc and Oakville Hydro participated in development of RIP report. The RIP report was published in Q1 2017. It is provided in Appendix H17 - Niagara RIP.

Figure 5.2.2 - 15: Niagara Region Transmission Network[34]

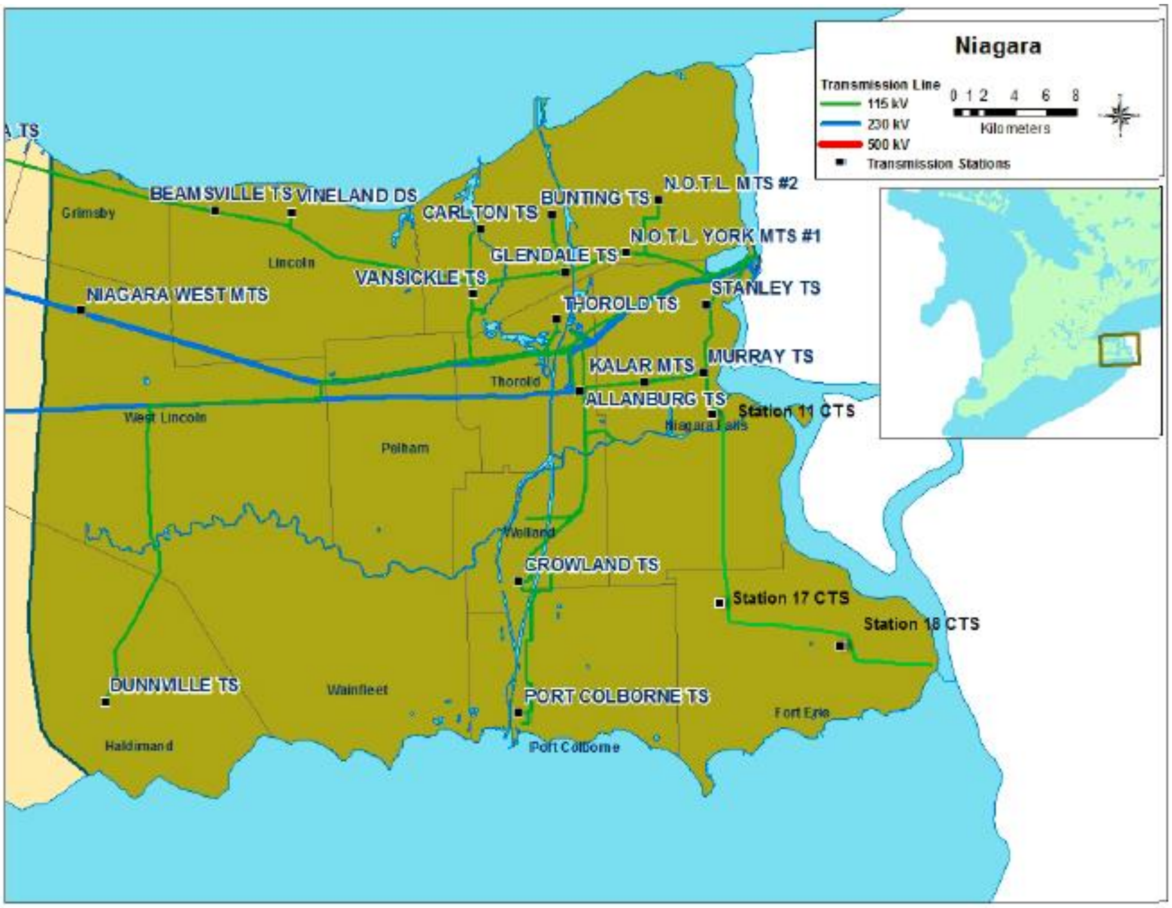


Figure 5.2.2 - 15 shows the Niagara region transmission network. The region's gross load is expected to grow at approximately 0.61% annually to 2024. The net load forecast when considering CDM and DG contribution is expected to decrease at an average rate of 0.26% annually to 2024.

Hydro One reviewed end of life equipment (autotransformers and power transformers) and proposed several sustainment initiatives in the RIP report. One particular finding was that the switchgear at Carlton TS, which supplies customers in Alectra Utilities' St. Catharines service

[34] Appendix H17 - Niagara RIP Page 11

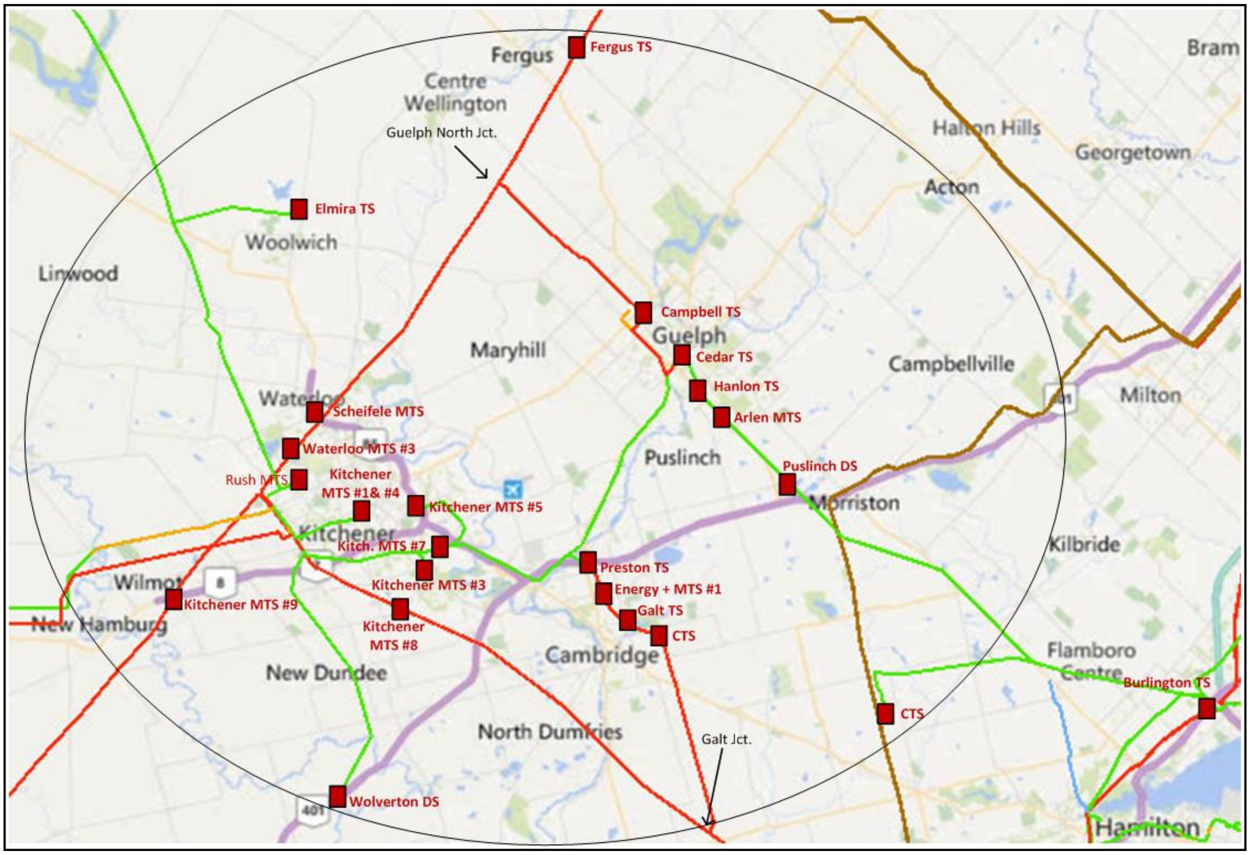
area, has been identified as being at end of life. Accordingly, Hydro One has planned to replace this switchgear by the end of 2021 and is currently in the process of preparing project estimates.

The next planning cycle is to be initiated in the next three to five years.

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, as shown in Figure 5.2.2 - 16. Alectra Utilities' service territory includes Guelph and Rockwood.

Figure 5.2.2 - 16: Kitchener, Waterloo, Cambridge and Guelph (KWCG) Region with Electrical Layout[35]



A Working Group consisting of staff from Cambridge and North Dumfries Hydro, Guelph Hydro Electric Systems Inc. (now part of Alectra Utilities), Kitchener-Wilmot Hydro, Waterloo North Hydro, Hydro One Networks Inc. and the IESO developed the KWCG Area IRRP in 2015. End of life refurbishments were already under way while the IRRP was being developed. In 2017, the Campbell TS T2 (75MVA) transformer owned and operated by Hydro One failed and was replaced with a larger capacity (100MVA) unit. In addition, at the end of 2018, the Campbell DESN's T1 transformer DESN was replaced with a 100 MVA unit.

[35] Appendix H18 - Kitchener – Waterloo – Cambridge – Guelph Region Needs Assessment Page 9

The IRRP described two initiatives designed to address demand growth in Guelph, Kitchener and Cambridge over the near-term and medium-term and improve the ability to restore supply to customers in Waterloo and Guelph. These projects are provided, as follows:

G.1 Guelph Area Transmission Reinforcement ("GATR") Project

In response to a hand-off letter to undertake a detailed study on the option of developing a second 115 kV/230 kV auto-transformer at Preston TS, Hydro One identified and examined a number of alternatives to reduce the impact of supply interruptions to customers in Cambridge and Kitchener in the event of a major transmission outage on the 230 kV system. Based on Hydro One's analysis, the installation of two 230 kV circuit switchers at Galt junction would:

- meet the Ontario Resource and Transmission Assessment Criteria ("ORTAC") 30-minute restoration criteria on the Cambridge-Kitchener 230 kV sub-system;
- provide regional benefits; and
- strike a reasonable balance between cost, reliability improvement, and feasibility.

This project was completed in 2017 and benefitted all of the LDCs in the region, including Alectra Utilities' predecessor Guelph Hydro.

G.2 M20D/M21D In-line Switches

In the event that a major outage occurred involving the loss of both transmission circuits on the Cambridge/Kitchener 230 kV system (M20/21D), all load supplied by M20D/M21D would be interrupted. The system could only restore up to 65 MW of electricity supply in Cambridge within 30 minutes via the 115 kV/230 kV auto-transformer and the circuit switchers at Preston TS. The system therefore did not meet the ORTAC criteria because more than 250 MW of load on the Cambridge-Kitchener 230 kV system would still be without service within 30 minutes of a major outage. To address this load restoration issue in Cambridge and Kitchener in the event of major transmission outages, the Working Group recommended proceeding with the installation of two 230 kV circuit switchers at Galt Junction, near Highway 3. The M20D/M21D in-line switches project was completed in April 2017.

The second Regional Planning cycle was initiated in 2018 and a NA Report for the KWCG area was issued on Dec 19, 2018. A copy is attached as Appendix H18 - Kitchener – Waterloo – Cambridge – Guelph Region Needs Assessment.

The 2018 NA reviews and affirms the needs/plans identified in the previous RIP and identifies and assesses system capacity, reliability, operation, and aging infrastructure needs. With respect to Guelph, Campbell TS (T3/T4) DESN overloading is forecasted to occur in 2021-2022. The 2018 NA has identified that, given the upgrades to the T1/T2 transformers, together with Hydro One's plans to replace secondary equipment to eliminate the station limiting constraint, there is sufficient capacity over the study period. Hydro One Transmission and Alectra Utilities will closely monitor loading at the T3/T4 Campbell TS DESN. Any excess loads will be transferred to T1/T2.

Community energy plans and other innovative solutions will be further considered in the SA phase of the second cycle of the regional planning process. At this point in the planning process, Alectra Utilities does not expect that capital investments will be required in the Guelph portion of its service territory to address the capacity related issues for Campbell TS. Depending on the nature of the implementation of Hydro One's plans for replacement of the secondary equipment, capital investments may or may not be required on Alectra Utilities' system in the Guelph area as a result of regional planning within the DSP planning period.

5.2.2.9 SUMMARY OF INVESTMENTS DRIVEN BY REGIONAL PLANNING

Table 5.2.2 - 6 summarizes the near term investments that Alectra Utilities plans to carry out as a result of its efforts to coordinate its distribution system planning through Regional Planning processes. The list below only includes investments relating to projects that have been identified in completed RIPs and IRRPs, and for which the solution and scope has been identified. There are four regional planning cycles underway and several additional sustainment/expansion initiatives have been identified during the NA phase of the Hamilton IRRP, which may require Alectra Utilities to initiate work and/or make capital contributions during the DSP planning period. These investments have not been included below, or in this DSP, due to the limited information presently available on the final solution and scope.

Table 5.2.2 - 6: Summary of Regional Planning Activities

Region or Sub-Region	Near Term Actions Identified	Project Reference	$MM (2020-2024)
Barrie/Innisfil	Design and construct Barrie TS feeder integration for 13M3 through 13M8, relocate the Midhurst 23M24 feeder currently located on the west side of the station and install Feeder Metering	150259	2.21
York	Construct a new 230/27.6kV DESN transformer station in the northwestern part of Markham (Markham TS#5).Distribution and/or transmission lines to connect the new transformer station. Alectra Utilities will complete a class EA for the transmission station	101488	0.72
GTA West	Off load Erindale TS. - Utilize 25M9 feeder from Jim Yarrow TS in Brampton to provide up to 25 MW of capacity to offload Erindale TS	150357	2.13
Greater Hamilton	Kenilworth TS power factor correction required (new capacitor bank to be installed in conjunction with planned HONI station upgrades at Kenilworth TS by 2021).	150587	0.56

5.2.2.10 IESO COMMENTS ON PROPOSED RENEWABLE ENERGY GENERATION INVESTMENTS

Alectra Utilities provided details regarding the number of Renewable Energy Generation ("REG") applications received, and its REG planning and investments required, to the IESO in January 2019, as described in Chapter 5.3.4 of this DSP. The IESO reviewed the REG information that was provided and concluded that Alectra Utilities' request for the IESO to provide a letter to satisfy the filing requirement in Chapter 5, section 5.2.2 was not needed as Alectra Utilities does not having any planned REG investments over the 2020-2024 DSP period.

5.2.3 PERFORMANCE MEASUREMENT FOR CONTINUOUS IMPROVEMENT

Alectra Utilities has been guided by its Asset Management Strategic Principles (introduced in Section 5.2.1 and described in detail in Section 5.3.1), as well as by the OEB's RRFE, in developing its approach to monitoring and measuring its performance with respect to:

- the quality of its Capital Investment Plan;
- the efficiency of its Capital Investment Plan implementation; and
- the extent to which its Asset Management Strategic Principles are met.

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 nine DSP-specific performance measures that are incremental to the measures that it already tracks and reports through the OEB's Scorecard process, for a total of 38 unique measures to be tracked by Alectra Utilities. This section of the DSP describes Alectra Utilities' performance measurement framework, including the company's specific performance metrics and how the framework drives performance relative to the outcomes articulated by Alectra Utilities' Asset Management Strategic Principles and by the OEB's RRF.

Due to the formation of Alectra Utilities in 2017, some of the measures do not have historical information for comparison. For measures where historical information is available, this section of the DSP provides a summary of the historical periods using the relevant performance measures and explains the impact of those historical trends on the development of the DSP[36].

[36] Information regarding capital expenditures for the 2015 and 2016 Historical Years is based on the capital plans of Alectra Utilities' individual predecessor utilities, which approached capital spending in a manner specific to their individual needs. This document represents Alectra Utilities' first DSP, and is a comprehensive plan that takes into account and balances system needs across its entire service territory. The 2015 and 2016 historical capital expenditure information has been prepared for purposes of meeting the Filing Requirements by mapping these historical expenditures for the individual predecessor companies to current activities where possible. As the 2015 and 2016 capital expenditure decisions were not made by Alectra Utilities but, rather, by separate corporate entities, that historical capital expenditure information does not provide an appropriate basis for comparison or from which reasonable conclusions can be drawn. See Appendix P – Historical Capital Expenditures for the historical expenditure data for 2015 and 2016 for each of the five predecessor utilities on an individual basis, which is provided for the sole purpose of satisfying the DSP Filing Requirements

5.2.3.1 PERFORMANCE MEASUREMENT FRAMEWORK

Alectra Utilities' DSP was developed based on the company's identified investment needs, which drive the planned outcomes that align with its Asset Management ("AM") Strategic Principles. Those principles, in turn, are derived from Alectra Utilities' Corporate Goals and Objectives. The AM Strategic Principles reflect the outcomes – financial, customer, operational, regulatory and organizational – that Alectra Utilities expects to realize from the implementation of the DSP and the Capital Investment Plan. In order to enable the company to track performance relative to its desired DSP outcomes, Alectra Utilities has established nine DSP-specific performance measures for the 2020-2024 DSP planning period, as set out in Table 5.2.3 - 1, below. This section provides a detailed description of the performance measures that are used by Alectra Utilities to track its performance in implementing the investments and initiatives set out in this DSP.

Table 5.2.3 - 1: Alectra Utilities 2020-2024 DSP Performance Management Framework

<table>
<tr><th colspan="2">AM Strategic Principle</th><th>DSP Performance Measures</th></tr>
<tr><td rowspan="2">Financial</td><td rowspan="2">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.</td><td>Cost Control (A) - Planned Capital (Actual vs Budget):
% of Planned Capital Projects Completed vs. Budget

Cost Control (B) - Planned Capital Projects Completed:
% of Planned Capital Projects Completed</td></tr>
<tr><td>Asset Condition: Health Index (Cable):
% of Underground Cable in Poor and Very Poor Health Index Condition</td></tr>
<tr><td rowspan="2">Customer</td><td>Evolve the distribution system to increase Alectra Utilities’ ability to meet current and future customer needs through a range of traditional and emerging solutions.</td><td rowspan="2">Customer Satisfaction Survey Results:
% of Customers > Somewhat Satisfied</td></tr>
<tr><td>Identify, understand and incorporate customer preferences and priorities to enable the appropriate integration of solutions, products and services on the grid.</td></tr>
<tr><td rowspan="2">Operational</td><td>Enhance operational effectiveness and system performance in alignment with Alectra Utilities’ long term plans by balancing the need for system renewal, system modernization and cost mitigation.</td><td>System Reliability:
• SAIDI – Excluding MED
• SAIFI – Excluding MED
• Customer Hours of Interruption (CHI) due to Defective Equipment</td></tr>
<tr><td>Increase monitoring, analytics and business intelligence capabilities to support operational excellence and continuous improvement.</td><td>Work Execution:
• Cost Performance Index (CPI)
• Schedule Performance Index (SPI)</td></tr>
</table>

In collaboration with internal stakeholders and taking into consideration customer needs, preferences and priorities identified through customer engagement, the Asset Management group developed the customer performance measures based on the AM Strategic Principles and desired outcomes of the activities included in the DSP. The Performance Measures have been endorsed by Alectra Utilities' Executive Management Team and intended to complement Alectra Utilities' Corporate Scorecard.

5.2.3.2 PERFORMANCE MEASURES

Given that Alectra Utilities was formed in 2017, and that it has undertaken significant efforts to integrate, harmonize and establish new processes, practices and systems since, many of the performance measures developed to track performance in respect of this DSP have not previously been used by the company. Consequently, Alectra Utilities does not have historical data for the new measures. On a go forward basis, Alectra Utilities intends to monitor, track results and consider this data in developing potential targets to drive future performance. Alectra Utilities' custom performance measures for the 2020-2024 period have been developed on the basis of the investment plans recommended by this DSP.

A Financial

In order to track performance, relative to the company's Financial AM Strategic Principle of prudently investing in and maintaining assets to provide sustainable value, Alectra Utilities has established two performance measures:

- Cost Control – Planned Capital versus Actual Expenditures
- Asset Condition – Health Index of Cable Assets

A.1 Cost Control: Planned Capital

A.1.1 Cost Control (A) – Planned Capital (Actual vs. Budget)

Measuring planned capital expenditures relative to actual capital expenditures enables Alectra Utilities to track its implementation of those capital investments that are within its control in terms of scope, schedule and cost. Regular and ongoing communications, meetings and discussions take place among representatives from the company's Program Delivery, Asset Management, Distribution Design, Network Operations (lines, construction) and Supply Chain Management groups to coordinate, provide updates and prioritize ongoing projects to ensure that work is completed on time and within budget. Completion of the planned capital investments within each investment group (e.g., Overhead Asset Renewal, Underground Asset Renewal) is tracked through the Enterprise Resource Planning ("ERP") system, which enables Alectra Utilities to monitor and report on its implementation of capital investments compared to its budgeted capital investments, and identify any areas of concern (i.e. deviations from budget, defined scope of work, timing of implementation) on an investment grouping basis.

Table 5.2.3 - 2(A): Finance: Cost Control Custom Performance Measure

Measure Category	2020-2024 Performance Measure	Historical Performance (2018)	Target (2020-2024)
Finance	Cost-Control: Planned Capital (Actual vs. Budget)	84%	100%

The Cost-Control performance measure tracks the cumulative implementation of planned capital investments relative to the plan as outlined in this DSP over the 2020-2024 period. Planned capital investments include those in the System Renewal and System Service investment categories, but exclude Reactive Capital investments because these are not within the control of Alectra Utilities. Alectra Utilities' DSP-specific performance measure for cost-control has been developed on the basis of the proposals, plans and associated investment funding contained in this Application.

A.1.2 Cost Control (B) – Planned Capital Projects Completed

Measuring planned capital project completion enables Alectra Utilities to track its implementation of those capital investments that are within the company's control in terms of scope, schedule and cost. Completion of the planned capital investments within each investment group (e.g., Overhead Asset Renewal, Underground Asset Renewal) is tracked through the Enterprise

Resource Planning system, which enables Alectra Utilities to monitor and report on its implementation of capital investments compared to its portfolio of planned capital investments, and identify any areas of concern (i.e., deviations from defined scope of work, timing of implementation, cost changes) on an investment grouping basis. Regular and ongoing communications, meetings and discussions take place among representatives from the company's Program Delivery, Asset Management, Distribution Design, Network Operations (lines, construction) and Supply Chain Management groups to coordinate, provide updates and prioritize ongoing projects to ensure that work is completed on time and scope.

Table 5.2.3 - 2(B): Finance: Cost Control Custom Performance Measure

Measure Category	2020-2024 Performance Measure	Historical Performance	Target (2020-2024)
Finance	Cost-Control: % of Planned Capital Projects Completed	N/A	Monitor

Since Alectra Utilities' Planned Capital Project Completed measure was developed in 2019, there are no historical measures available. Alectra Utilities will measure and track its Planned Capital Projects Completed levels using the performance measure over the duration of the DSP implementation period to establish a baseline from which it may in future propose a target.

A.2 Asset Condition – Health Index (Underground Cables)

Alectra Utilities' performance relative to the Financial AM Strategic Principle of prudently investing in and maintaining assets to provide sustainable value is also tracked by monitoring asset condition. Measuring asset condition performance based on the Health Index for Alectra Utilities' underground cable assets enables the company to track its pacing and direction of critical system renewal initiatives aimed at renewing underground cable assets that are in very poor and poor condition. Underground Cable and cable accessory failures are the leading cause of outages, both in terms of frequency and duration. Over the last five years[37], Alectra Utilities has experienced an increasing year-over-year trend of underground cable failures. Alectra Utilities has determined that an increasing rate of underground cable failure over this period is an indication that the deterioration of cables is exceeding the historical renewal rate. Please refer to

[37] Alectra Utilities has consolidated historical outage statistics from predecessor utilities related to cable and cable accessory failures from 2014 to 2018.

section 5.2.3.2 – C.1.3 – Customer Hours of Interruption from Defective Equipment for a detailed explanation of the impact of deteriorating underground cables on system reliability over the last five years. To address this adverse trend, Alectra Utilities has determined that it needs to increase the pace and scope of underground cable renewal in particular. Upon the formation of Alectra Utilities in 2017, the Asset Management group was consolidated and a new, uniform approach to Asset Condition Assessment was established for the company. Consequently, Alectra Utilities does not have comparable historical health index information for its underground cable assets. The Health Index for underground cable assets from the 2018 Asset Condition Assessment has been referenced as the starting point for this performance measure.

Alectra Utilities determines the condition of its assets through the computation of an asset's Health Index ("HI"), which is a quantitative representation of the condition of a specified asset class, expressed on a scale ranging from very good (HI greater or equal to 85%) to very poor (HI less than 25%). A HI of "very poor" indicates assets with major degradation or are likely to experience imminent failure. For a detailed description of the Asset Condition Assessment methodology and process used to determine system renewal pacing and prioritization, please refer to Appendix D - Asset Condition Assessment – 2018.

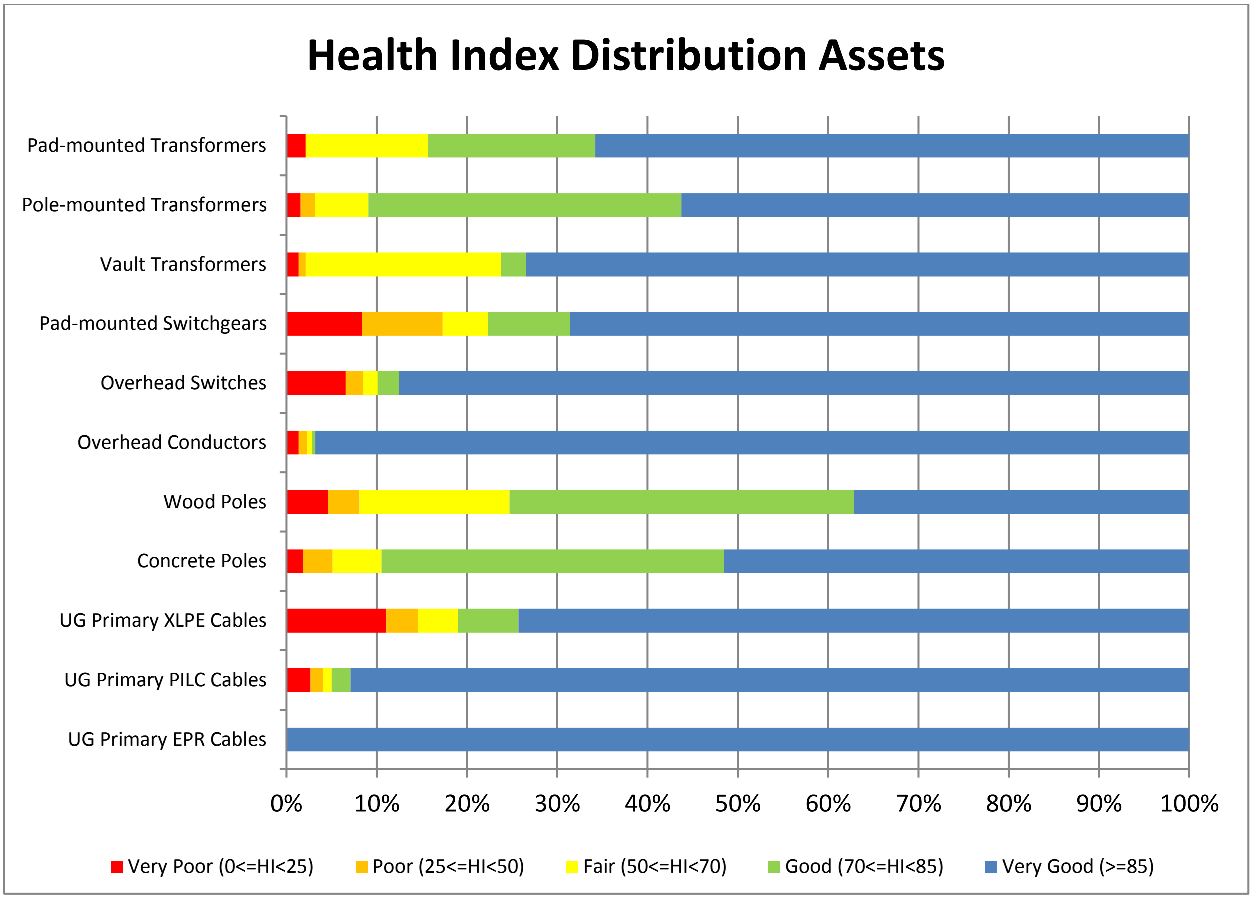
Table 5.2.3 - 3: Finance: Asset Condition Custom Performance Measure

Measure Category	2020-2024 Performance Measure	Historical Performance (2018)	Target (2020-2024)
Finance	% of Cable in Poor and Very Poor (Health Index) Condition	14%	Monitor

Alectra Utilities manages 22,140 km of underground cable across its territory, 14% of the total population is in deteriorated condition (Very Poor and Poor Health Index). Deteriorated cables are highly susceptible to failure causing significant reliability impacts. The quantity of deteriorated cables is 3,173 km (i.e. 14% of 22,140 km), which is a substantial. Alongside the significant quantity of deteriorated underground cable, addressing cables involves long-lead time for materials and requires significant planning, design and permit acquisition to execute. Alectra Utilities has experienced that once the cable has reached end of life, the failure rate increases and that the cables can no longer be repaired and the only option is to replace the cable. This impact of increasing failure rate is compounded by the inherent lag in project execution which erodes service and customer confidence. Alectra Utilities will address the deteriorated population of cables in a proactive manner. Alectra Utilities has determined that, with sufficient pacing and prioritization of assets in need of renewal, the Health Index of an asset class can be improved in a proactive manner. From 2020 to 2024, Alectra Utilities plans to address a significant amount of underground cable identified with a Health Index of Poor and Very Poor. The Health Index of Underground Primary Cables, as illustrated in Figure 5.2.3 - 1, indicates that a significant portion of the underground cable population has been determined to be in poor or very poor condition and therefore requires renewal to be sufficiently paced and prioritized. From 2015 to 2018, cable failures were the leading contributor to outages within the service territory now served by Alectra Utilities, at a growing rate.[38] To reverse this adverse trend, Alectra Utilities plans to rehabilitate or replace 2,184 km of underground cable over the five years DSP planning period, which represents 69% of the 3,173 km of underground cable identified as being in Poor or Very Poor condition as indicated in the 2018 Asset Condition Assessment. Figure 5.2.3 - 1 illustrate the distribution of health indices for Alectra Utilities.

[38] Historical

Figure 5.2.3 - 1: Distribution Asset Health Index Summary (2018)



The Health Index of underground cables in poor and very poor condition represents the current level and future risk of failure. Alectra Utilities leverages the Health Index metric as an indicator of the required level of investment over a long term planning horizon to enable pacing and prioritization of renewal investments. Please refer to Appendix A10 - Underground Asset Renewal for a detailed explanation of the methodology used to derive the pacing and renewal prioritization for underground cables.

B Customer

In order to track performance relative to the company's Customer AM Strategic Principles of evolving the distribution system to increase its ability to meet current and future customer needs and identifying, understanding and incorporating customer preferences and priorities, Alectra Utilities has established one performance measure, which is based on its annual customer survey results. In particular, Alectra Utilities will measure the percentage of customer responses that are at least somewhat satisfied. Alectra Utilities will measure and track its customer satisfaction levels using the performance measure over the duration of the DSP implementation period to establish a baseline from which it may in future propose a target.

Alectra Utilities has engaged Simul Corp., an external research firm, to conduct customer satisfaction surveys in 2019. The surveys helps Alectra Utilities understand the satisfaction levels of its customers relative to Ontario and national comparators. In addition, it helps Alectra Utilities understand how customers' perception, issues and concerns are changing over time.

Table 5.2.3 - 4: Customer Satisfaction Custom Performance Measure

Measure Category	2020-2024 Performance Measure	Historical Performance	Target (2020-2024)
Finance	Customer Satisfaction	N/A	Monitor

C Operational

In order to track performance relative to the company's Operational AM Strategic Principles of enhancing operational effectiveness and system performance in alignment with long-term plans, preparing the distribution system for new technologies and increasing monitoring, analytics and business intelligence capabilities to support operational excellence, Alectra Utilities has established four DSP-specific performance measures, in the following two groups:

C.1 System Reliability

C.2 Work Execution

C.1 System Reliability

With respect to System Reliability, Alectra Utilities has established three DSP-specific performance measures. These will enable the company to track performance relative to its Operational AM Strategic Principle of enhancing operational effectiveness and system performance in alignment with its long-term plans by balancing the need for system renewal, system modernization, and cost mitigation. Alectra Utilities' reliability data is the culmination of five different utilities that did not collect all information related to reliability in a uniform fashion. The level of granularity in this DSP while detailed is not the end state. Alectra Utilities has already setup a more detailed framework for reliability reporting as consolidation of the OMS and SCADA systems progress. Ultimately, with respect to system reliability, Alectra Utilities seeks to reverse the deteriorating reliability trend that it has experienced over the last five years. These three measures are incremental to the System Reliability measures reported on by Alectra Utilities for purposes of the Electricity Distributor Scorecard (EDS). The three incremental System Reliability performance measures are:

C.1.1) System Average Interruption Duration Index (SAIDI) Excluding Major Event Days
C.1.2) System Average Interruption Frequency Index (SAIFI) Excluding Major Event Days
C.1.3) Customer Hours of Interruption due to Defective Equipment

This section explains the purpose of and manner of calculation for each measure, how Alectra Utilities identifies the causes underlying the historical trends seen with respect to these measures, and the steps taken by the company to address the adverse trends, which are indicative of deteriorating system reliability, experienced over the last five years.

Inclusion of Loss of Supply Outages in System Reliability Performance Measurement

Alectra Utilities understands the importance for its customers of reliable electricity service, including their expectations for expedient system restoration upon the occurrence of an outage event. Alectra Utilities recognizes that specific outage events are beyond its control but understands that all outages, including Loss of Supply[39] ("LOS") events, negatively impact customers. In the second phase of customer engagement, Alectra Utilities has received support for implementing back up solutions that enable quicker restoration of power in loss of supply or severe weather events. 61% of residential customers that participated in the survey supported Alectra Utilities' plan of implementing the proposed solution at the recommended pace or accelerated pace. Similarly, business customer supported the plan (58% of small business, 96 of 158 mid-sized business and 13 of 18 large users). Alectra Utilities is responsive to these customer concerns and has included DSP specific investments to mitigate the impacts of all outage events and to expedite the restoration of service following outages caused by LOS outages. To address outages as a result of LOS, Alectra Utilities has established practices to work with upstream and

[39] Loss of Supply outages are defined as cause of outage – Code 2, customer interruption due to problems associated with assets owned and/or operated by another party, and/or in the bulk electricity supply system.

neighbouring utilities to mitigate the number and duration of LOS outages and incorporated plans to minimize the number of customers and duration of outages should LOS events occur.

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. Such catastrophic days are measures using an industry standard Major Event Day methodology described in detail below. Alectra Utilities considers such Major Event Days as unforeseen events beyond reasonable control which immensely inhibit the organizations ability to perform and supply reliable service. For DSP-specific performance measures, Alectra Utilities monitors and tracks reliability based index measures without outages related to Major Event Days.

C.1.1 SAIDI Excluding Major Event Days

SAIDI is a measure in hours of the annual system average interruption duration for customers served. SAIDI represents the quotient obtained by dividing the total customer hours of interruptions longer than one minute by the number of customers served. SAIDI is the average number of hours a customer has been interrupted in the year.

Equation 5.2.3 - 1: System Average Interruption Duration Index

$$SAIDI = \frac{\text{Sum of all customer interruption durations}}{\text{Total number of customers served}}$$

A Major Event Day (MED) is a day in which the daily SAIDI exceeds a MED threshold value (T_{MED}). 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 ‘1 Day Rolling Beta’ method to identify MEDs as per 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 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 outage contributors, 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 (2014 – 2018), organized by year and by operational area or predecessor utility.

Figure 5.2.3 - 2: SAIDI vs. SAIDI Excluding MEDs from 2014 to 2018

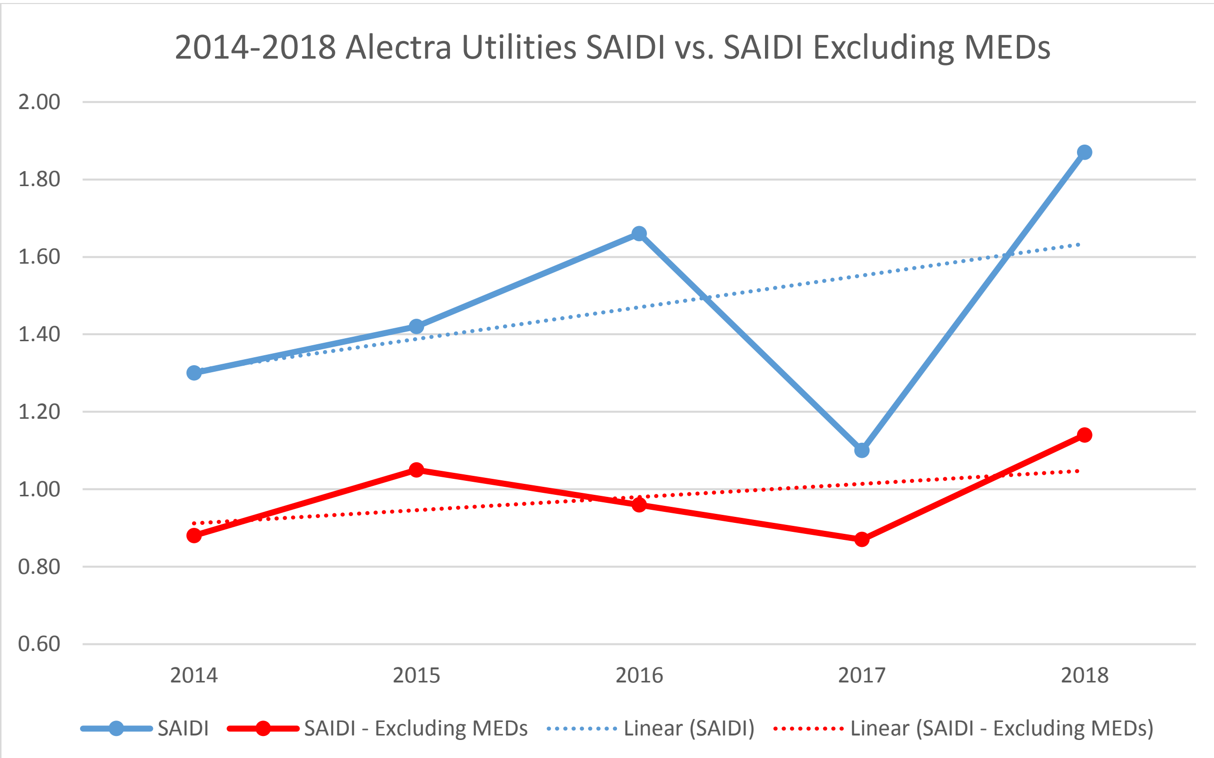


Table 5.2.3 - 5: Alectra Utilities' SAIDI, SAIDI Excluding MEDs, LOS Results from 2014 to 2018

Metric (Hours)	2014	2015	2016	2017	2018
SAIDI	1.30	1.42	1.66	1.10	1.87
SAIDI - Excluding MEDs	0.88	1.05	0.96	0.87	1.14
SAIDI - Excluding LOS	1.12	1.35	1.24	1.03	1.66
SAIDI - Excluding MEDs and LOS	0.84	1.00	0.83	0.80	1.04

Figure 5.2.3 - 2 and Table 5.2.3 - 5 illustrate an increasing system average interruption duration trend at Alectra Utilities (including its predecessors) since 2014. The five year SAIDI measure indicates a 16% increase on annual average system outage duration that Alectra Utilities customers' service was interrupted. When MEDs are excluded, the 2018 SAIDI measure indicate a 8% increase in annual outage duration since 2014. This trend is not acceptable to Alectra Utilities. In the second phase of customer engagement, Alectra Utilities received strong support

for underground system renewal. 73% of residential customers that participated in the second phase of customer engagement indicated support for the recommended or accelerated pace of the renewal. Preference to proceed with underground renewal investments was also received from business customers (65% of small business, 97 of 137 mid-sized business and 10 of 13 large users) who prefer the recommended or accelerated pace. Based on the need of investment and strong customer preference for underground system renewal, Alectra Utilities has incorporated into plans the accelerated pace for underground cable renewal.

Please refer to section 5.2.3.2 - C.1.2.1 - Factors Contributing to Adverse Trends in SAIDI and SAIFI for a detailed explanation.

As such, the company is planning to implement appropriate and prudent solutions to address this adverse trend in reliability performance, and has established priorities and pacing for investments to reverse this trend over the DSP planning period. The system renewal investments proposed in the DSP are to maintain the five year historical system performance levels and improve reliability for identified areas that are experiencing below average reliability performance.

Table 5.2.3 - 6: System Reliability (SAIDI – Excluding MED) Custom Performance Measure

Measure Category	2020-2024 Performance Measure	5-Year Historical Performance	Target (2020-2024)
Operational	SAIDI – Excluding MEDs	0.98 hours	Maintain

C.1.2 SAIFI Excluding Major Event Days

SAIFI is a measure of the annual frequency of service interruptions for customers served. SAIFI represents the quotient obtained by dividing the total number of customer interruptions longer than one minute by the number of customers served. SAIFI is the average number of sustained outages a customer has experienced in the year.

Equation 5.2.3 - 2: System Average Interruption Frequency Index

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

Figure 5.2.3 - 3: SAIFI vs. SAIFI Excluding MEDs from 2014 to 2018

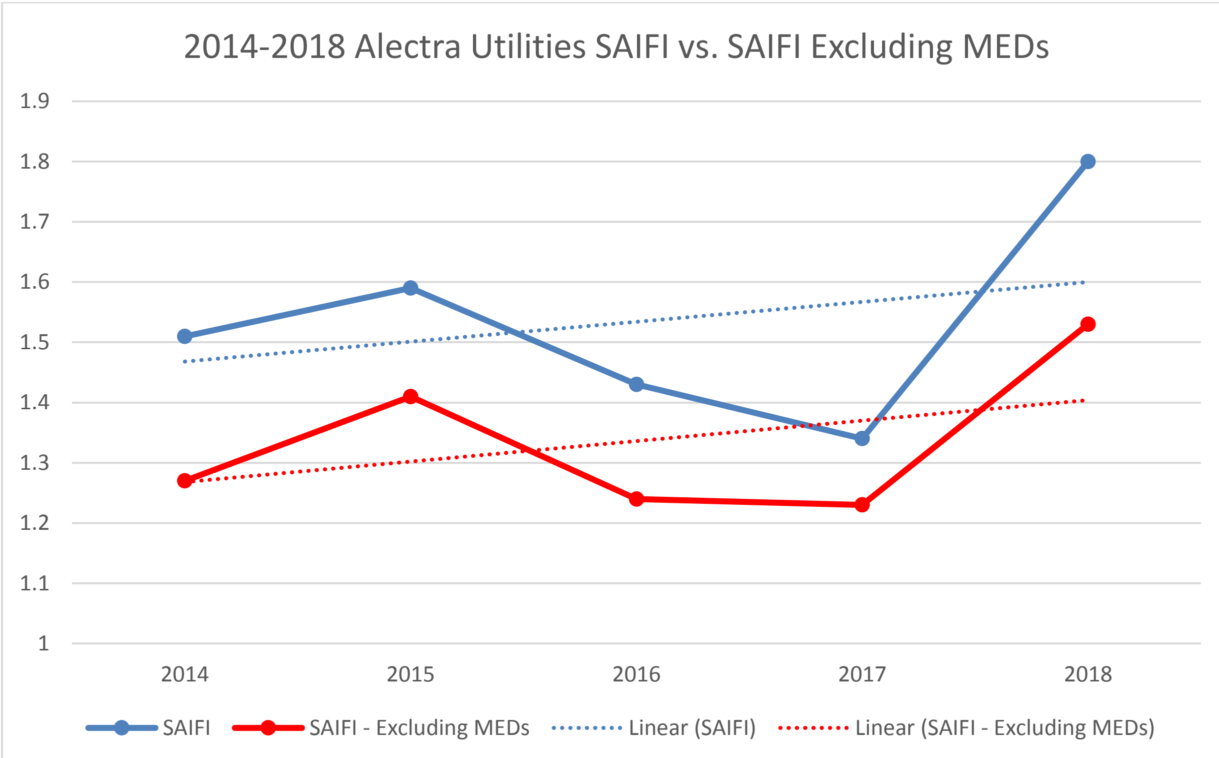


Table 5.2.3 - 7: Alectra Utilities' SAIFI, SAIFI Excluding MEDs, LOS results from 2014 to 2018

Metric (Number of Outages)	2014	2015	2016	2017	2018
SAIFI	1.51	1.59	1.43	1.34	1.8
SAIFI - Excluding MEDs	1.27	1.41	1.24	1.23	1.53
SAIFI - Excluding LOS	1.40	1.38	1.24	1.22	1.57
SAIFI - Excluding MEDs and LOS	1.21	1.23	1.09	1.11	1.33

Figure 5.2.3 - 3 and Table 5.2.3 - 7 illustrate a trend of increasing system average interruption frequency at Alectra Utilities (including its predecessors) over the five year period from 2014 to 2018. The five year SAIFI measure indicates a 6% increase on annual average system outage frequency that Alectra Utilities customers' service was interrupted. When MEDs are excluded, the SAIFI measure also indicate a 6% increase in annual outage duration since 2014. This trend is not acceptable to Alectra Utilities. In the second phase of customer engagement, Alectra Utilities received strong support for underground system renewal. 73% of residential customers that participated in the second phase of customer engagement indicated support for the

recommended or accelerated pace of the renewal. Preference to proceed with underground renewal investments was also received from business customers (65% of small business, 97 of 137 mid-sized business and 10 of 13 large users) who prefer the recommended or accelerated pace. Based on the need of investment and strong customer preference for underground system renewal, Alectra Utilities has incorporated into plans the accelerated pace for underground cable renewal. Please refer to section 5.2.3.2 - C.1.2.1 - Factors Contributing to Adverse Trends in SAIDI and SAIFI for a detailed explanation.

Alectra Utilities has put in place appropriate and prudent solutions to address this worsening trend in reliability performance and has established priorities and pacing for investments to reverse this trend. The system renewal investments proposed in the DSP are to maintain the five year historical system performance levels and improve reliability for identified areas that are experiencing below average reliability performance. Please refer to Section 5.4.3 for a list of capital investments planned by Alectra Utilities to address system reliability issues.

Table 5.2.3 - 8: System Reliability (SAIFI – Excluding MED) Custom Performance Measure

Measure Category	2020-2024 Performance Measure	5-Year Historical Performance	Target (2020-2024)
Operational	SAIFI – Excluding MED	1.34	Maintain

C.1.2.1 Factors Contributing to Adverse Trends in SAIDI and SAIFI

While the performance measures described above indicate adverse trends in system reliability, to understand the factors contributing to these adverse trends Alectra Utilities has undertaken analysis of its outage ‘cause codes’, which are part of the company’s system of identifying and tracking the root causes of outages affecting system equipment and customers. The cause codes are aligned with standard industry outage cause codes and OEB reporting requirements.

Figure 5.2.3 - 4 provides an outage cause code summary for Alectra Utilities from 2014 to 2018 by customer hours of interruption, and includes scheduled outages. The top four contributors to outage duration include Defective Equipment, Adverse Weather, Loss of Supply and Foreign Interference.

Figure 5.2.3 - 4: Alectra Utilities Five Year (2014-2018) Average Customer Hours of Interruption by Outage Cause Code

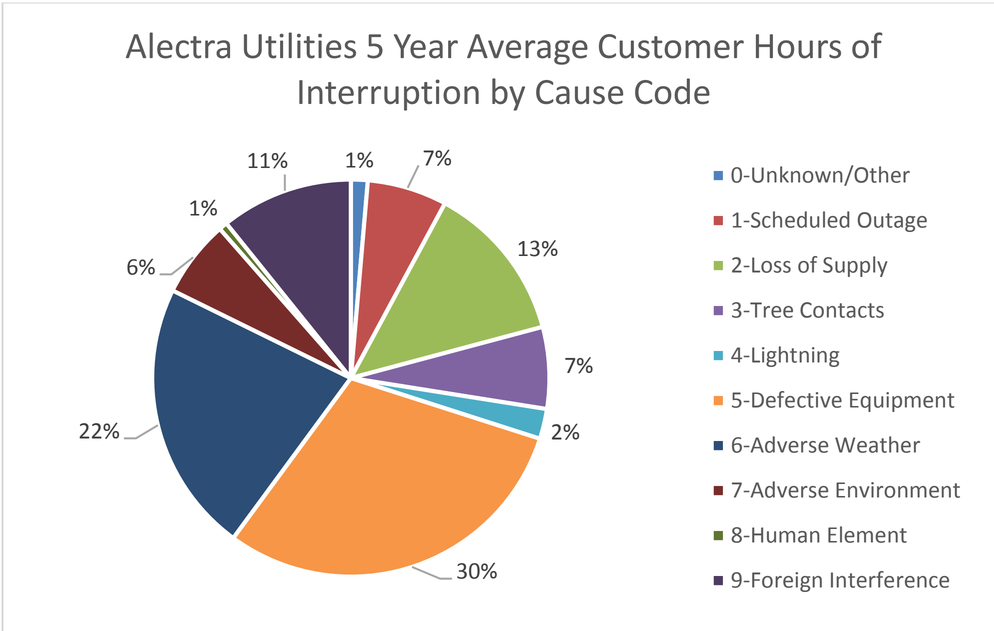
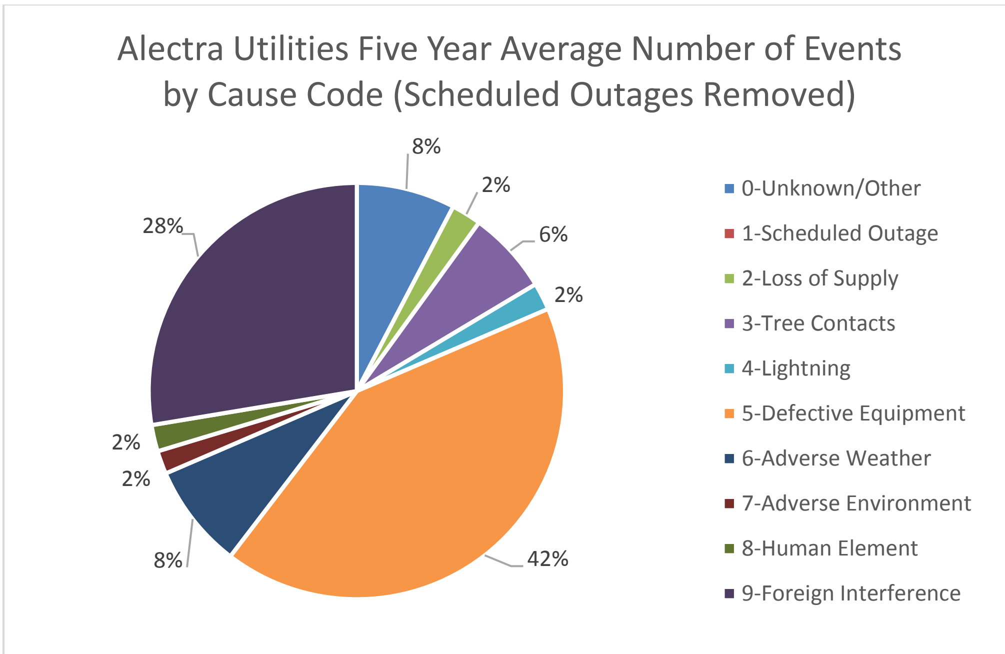


Figure 5.2.3 - 5 provides an outage cause code summary for Alectra Utilities from 2014 to 2018 by the number of outage events, and excludes scheduled outages[40]. Although scheduled outages are necessary for Alectra Utilities to safely and effectively maintain and renew the distribution system equipment, Alectra Utilities has incorporated practices to minimize the duration and inconvenience of customers caused by such outages. The top three contributors to outage event frequency by number of events, excluding scheduled outages, are Defective Equipment, Foreign Interference and Adverse Weather.

[40] Alectra Utilities has consolidated historical outage statistics from predecessor utilities from 2014 to 2016 based on OEB defined System Reliability Measures (EB-2014-0189).

Figure 5.2.3 - 5: Alectra Utilities Five Year (2014-2018) Average Number of Events by Cause Code (Excluding Scheduled Outages)

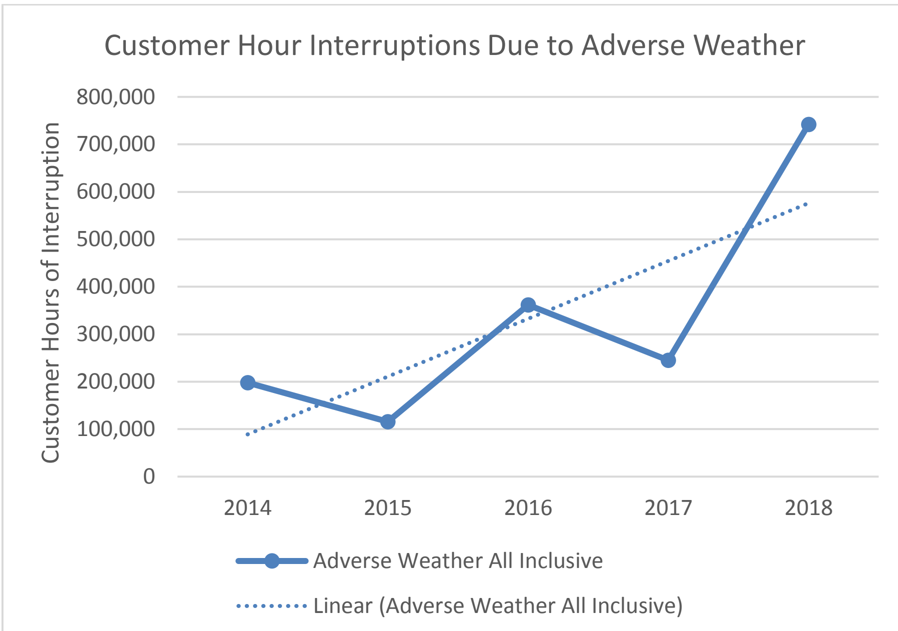


Alectra Utilities is guided to develop remedial solutions identified by the cause codes categorized by the number of hours of customer interruption and as well as the number of events. Alectra Utilities recognizes that Defective Equipment is the leading contributor in both duration and frequency of outages over the last five years and has set a DSP-Specific performance measure to track progress of addressing the Customer Hours of Interruption Due to Defective Equipment as explained in Section C.1.3, below. The following section provides a detailed explanation of reliability trends due to outages resulting from Adverse Weather and Foreign interference which are both top contributors in outage duration and frequency over the last five years.

Adverse Weather

As discussed in 5.2.1, Alectra Utilities' customers have expressed a preference for the company to construct, and invest in renewing, the distribution system in a manner that mitigates the impacts of adverse weather events, as well as to invest in solutions that expedite restoration of the system following adverse weather-caused outages.

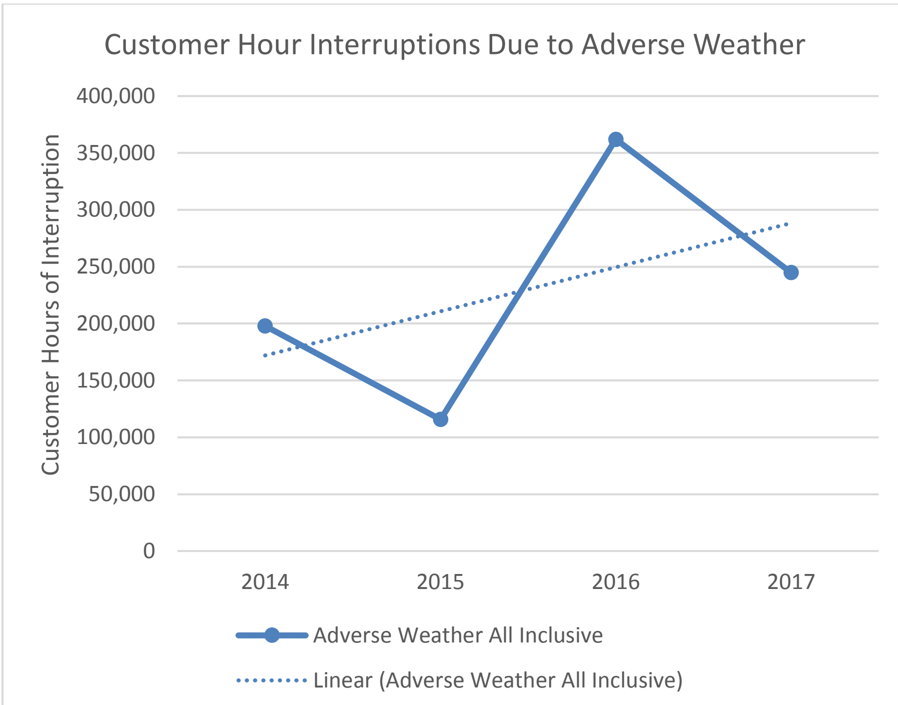
Figure 5.2.3 - 6: Customer Hours of Interruption Due to Adverse Weather from 2014 to 2018 at Alectra Utilities (including Predecessor Utilities)



Since 2014, Alectra Utilities (including its predecessors) has experienced a trend of increasing outage duration due to adverse weather. Figure 5.2.3 - 6 illustrates that Alectra Utilities has experienced an average annual increase of 86% of customer hours of interruption from adverse weather conditions from 2014 to 2018. Alectra Utilities has considered the impact of the significant increase of adverse weather events experienced in 2018 relative to the five year trend. To ensure that 2018 adverse weather related outages did not skew the five year trend, Alectra Utilities reviewed the four year trend from 2014 to 2017 as illustrated in Figure 5.2.3 - 7. The four year trend without 2018 adverse weather customer hours of interruption indicates an average annual increase of 46% from 2014 to 2017. Notwithstanding the adverse weather events in 2018, Alectra

Utilities' customers have continued to experience an increasing trend in customer hours of interruption since 2014.

Figure 5.2.3 - 7: Customer Hours of Interruption Due to Adverse Weather from 2014 to 2017 at Alectra Utilities (including Predecessor Utilities)



Considering the increasing trend in the number of hours of interruption due to adverse weather events with and without 2018 outages, and having regard to the expressed preferences of its customers, Alectra Utilities is compelled to implement remedial solutions to ensure it operates a reliable and dependable distribution system that is more resilient to such adverse weather events and that enables the prompt restoration of service following an outage.

The impact of adverse weather on reliability has a direct relation to asset condition. Assets in good condition are able to manage storms much better than assets in poor condition. The larger the volume of assets vulnerable to adverse weather are clustered together, the worse the impacts are. While the number of adverse weather events in the absence of 2018 is decreasing the impact is still increasing (customer hours). This is proof in the correlation between adverse weather and reliability impact. While fewer events are occurring, the assets in poor condition are failing catastrophically or several assets are failing which is why the hours of interruption are increasing.

This increases restoration time which is why adverse weather events are having a greater impact on reliability.

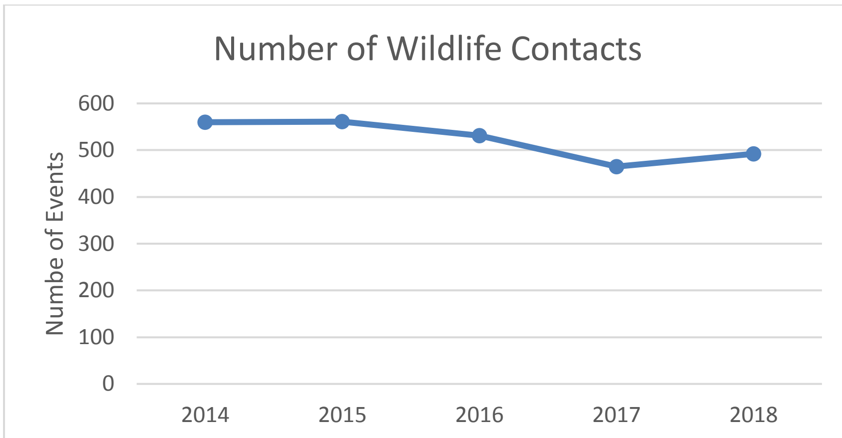
Additionally, in Figure 5.2.3 - 10 it highlights that OH Line Hardware is the second highest cause of equipment related failures. This link, between OH assets in poor condition having impacts on reliability is directly influenced by adverse weather. While the asset may be capable of operating in poor condition the stress during the adverse weather period causes failure and impacts reliability.

If not addressed in an urgent and meaningful way, Alectra Utilities' system will continue to be exposed to an increasing number of outages due to adverse weather. To address this risk, and the concerns of its customers, Alectra Utilities has developed plans to mitigate the impacts of storms through the renewal of its distribution system using present day standards, investments in storm-hardening initiatives, as well as renewal of the overhead distribution system in areas susceptible to adverse weather conditions. Please refer to Section 5.4.3 for details pertaining to capital investment solutions in Appendix A05 - Overhead Asset Renewal (Part A).

Foreign Interference

The Foreign Interference outage cause is much simpler for Alectra Utilities to segregate into sub-causes as there are only two main contributors. Vehicle Incidents (e.g. Pole, Transformer, Switchgear Hits) and Animal Contacts, with vehicle related issues being the primary cause and animal contacts secondary. Although vehicle contacts are significantly outside of Alectra Utilities' control, the company continues to evolve its protection controls and system switching capabilities to minimize the frequency and duration of impacts for customers as a result of such accidents. Where Alectra Utilities determines a pattern with vehicle related pole hits, investigation into the relocation of the pole to a more favourable location or the use of bollards will be examined. As a last resort Alectra Utilities would consider converting to underground as a solution, considering that the economic cost benefit warrants such a solution. Alectra Utilities has set plans to mitigate the impact of wildlife contacts through the implementation of guards to prevent accidental contacts. Figure 5.2.3 - 8 provides the number of wildlife contacts each year from 2014 to 2018 for Alectra Utilities (including its predecessors). While there has been a downward trend in the number of events, foreign interference continues to be a significant factor in contributing to outage duration and frequency. Alectra Utilities must continue to invest in renewing the distribution system to present day standards and continue to implement animal contact guards as required. Please refer to Section 5.4.3 for details pertaining to capital investment solutions in Appendix A05 - Overhead Asset Renewal and Appendix A07 - Rear Lot Conversion.

Figure 5.2.3 - 8: Number of Wildlife Contacts from 2014-2018 at Alectra Utilities



C.1.2.2 Addressing Reliability Issues on Worst Performing Feeders

Alectra Utilities manages reliability performance at the feeder level which provides insight on specific areas with substandard performance due to a long duration of outages, high frequency of outages, high number of momentary outages or a combination of duration, frequency and momentary events.

On an annual basis, Alectra Utilities assesses feeders and identifies the worst performing based on criteria of number of outage events, number of momentary outages, duration of outages as well as a combination of events and duration. For example, feeders which year after year provide significant contributions to SAIDI, SAIFI, or have significant momentary outages are flagged. Alectra Utilities identifies these feeders further into service areas and develops a list of feeders which have poor reliability.

Based on the factor which has the greatest influence on the feeder (i.e., duration or frequency), Alectra Utilities implements appropriate corrective actions. For example, feeders with significant duration may be candidates for automation which enables Alectra Utilities to expeditiously restore service. Feeders with frequent outages would be systematically reviewed for cause, and then remediation's plans implemented accordingly. For example, feeders with high animal contacts would be candidates for animal contact guards, feeders with significant cable failures would be candidates for cable replacement or injection. Details are provided in Appendix F - Worst Performing Feeders Report.

C.1.3 Customer Hours of Interruption from Defective Equipment

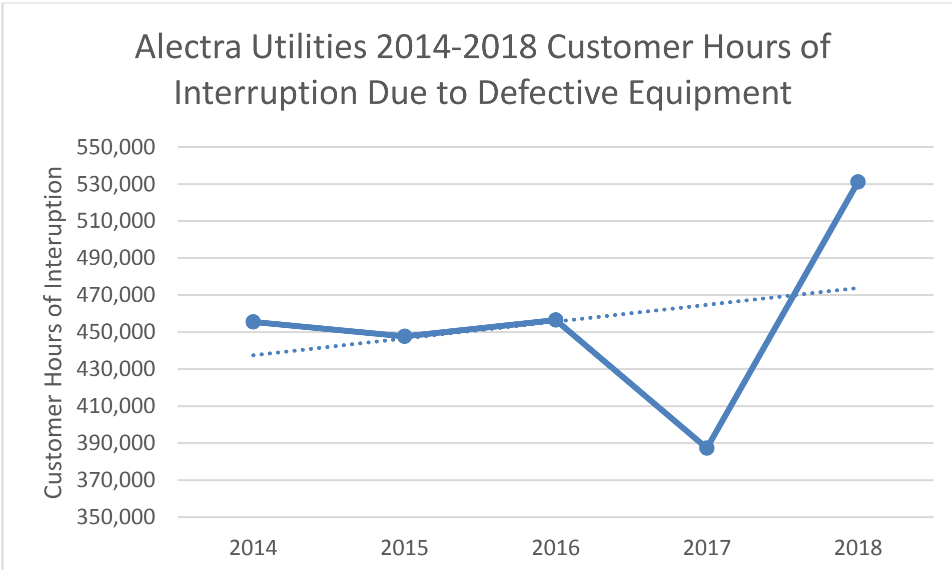
Customer Hours of Interruption ("CHI") are the total number of hours of interruption a customer or group of customers experience from sustained outages.

From 2014 to 2018, defective equipment was the contributing cause for 30% of the outage duration and 42% of the cause of the outage at Alectra Utilities (including its predecessors). The duration of outages due to defective equipment has increased from 2014 to 2018 by an annual average rate of 6%. Figure 5.2.3 - 9 illustrates the increasing trend in customer hours of interruption due to defective equipment during this period. Although a reduction was seen in the number of hours of customer interruption due to defective equipment in 2017, the overall trend indicates an annual average rate of increase over the five-year period. While Alectra Utilities continues to invest in system renewal and system maintenance to enhance sustainment, the increasing trend in customer hours of interruption due to defective equipment indicates that the rate of asset degradation is greater than the historical pace of renewal. Please refer to Section 5.3.3 for a detailed explanation of Alectra Utilities asset lifecycle management practices and results from the 2018 Asset Condition Assessment. Alectra Utilities has therefore developed plans to increase system renewals in specific equipment classes, such as underground cables, switchgear and overhead assets, to reverse this adverse trend.

Table 5.2.3 - 9: System Reliability (CHI – Defective Equipment) Custom Performance Measure

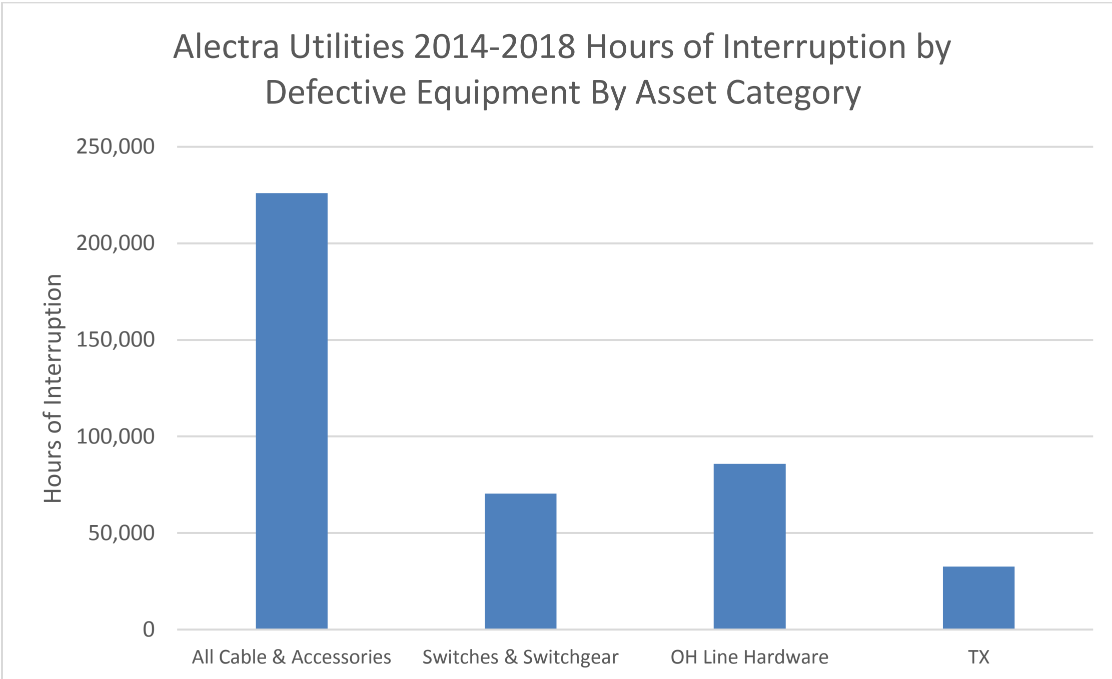
Measure Category	2020-2024 Performance Measure	5-Year Historical Performance	Target (2020-2024)
Operational	CHI – Defective Equipment	455,651 Hours/Year	Maintain

Figure 5.2.3 - 9: Customer Hours of Interruption Due to Defective Equipment at Alectra Utilities from 2014 to 2018



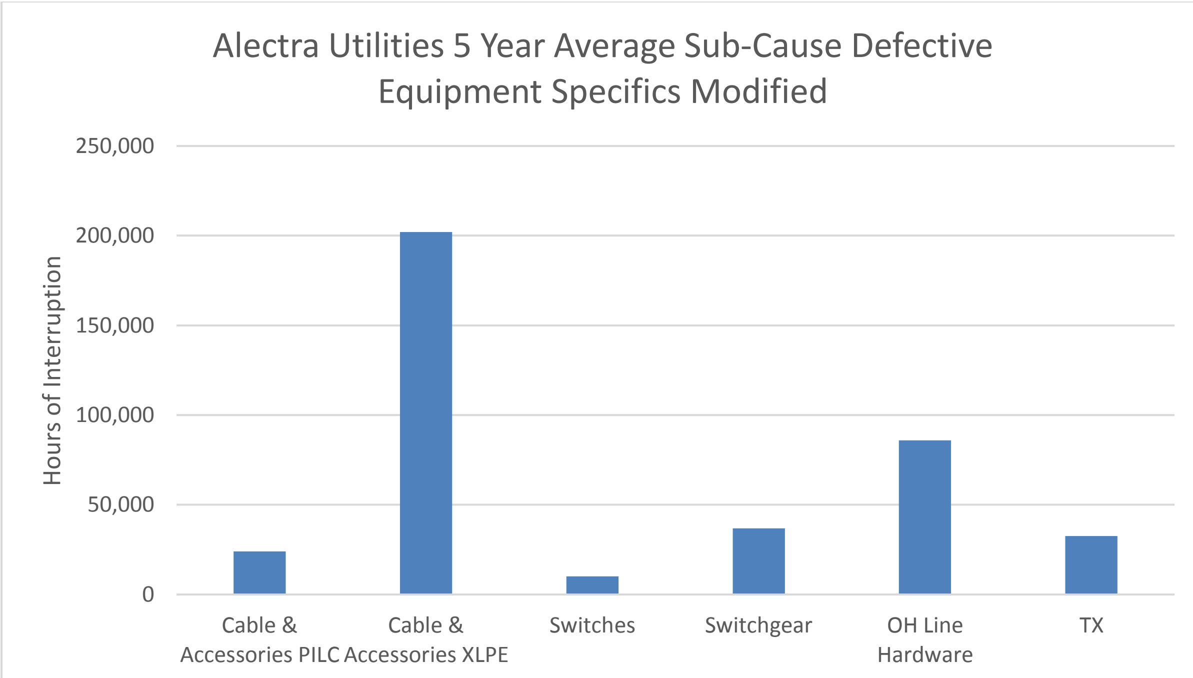
Closer examination of the five year historical defective equipment outages, that drove customer hours of interruption, informs Alectra Utilities of specific renewal investment needs. Figure 5.2.3 - 10 provides the four major sub-causes that account for 91% of all defective equipment interruption hours at Alectra Utilities (and its predecessors) from 2014 to 2018.

Figure 5.2.3 - 10: Alectra Utilities 2014-2018 Sub-Causes of Defective Equipment



Alectra Utilities has further examined each asset category to better understand the root causes of defective equipment outages. Figure 5.2.3 - 11 illustrates the the sub-classification of specific asset categories (i.e., Paper Insulated Lead Covered ("PILC") cables vs Cross-linked Polyethylene cables ("XLPE")), which caused customer interruptions during the 2014 to 2018 period. As Alectra consolidated historical outage information from its legacy utilities, the historical categorization of asset sub-categories had to be harmonized to reflect a consistent and uniform compilation of historical trends adequately. However, for a limited number of equipment groups, Alectra Utilities had to categorize and allocate historical outage causes. Two of the five legacy utilities reported switchgear and switch failures under similar sub-cause code groupings. For such situations, Alectra Utilities allocated historical outages between asset categories under one previously reported sub-cause code based on outage experiences from the same asset equipment at the other three legacy utilities.

Figure 5.2.3 - 11: Alectra Utilities 5 Year (2014-2018) Average Sub-Cause Defective Equipment Specifics by Customer Hours of Interruption Modified to Account for Switchgear Failures



The allocation of defective equipment outage causes by specific asset sub-classes provides a more detailed reflection of equipment related failures and provides Alectra Utilities with a clear indication of the most problematic assets:

- XLPE Cables (37% of all events and 44% of the total duration for Defective Equipment; 16% of all events and 13% of total duration of all outages per Figure 5.2.3-4 and Figure 5.2.3-5)
- Overhead Line Hardware (12% of all events and 19% of the total duration for Defective Equipment; 5% of all events and 6% of total duration of all outages per Figure 5.2.3-4 and Figure 5.2.3-5), and
- Switchgears (4% of all events and 9% of the total duration for Defective Equipment; 2% of all events and 3% of total duration of all outages per Figure 5.2.3-4 and Figure 5.2.3-5)

Alectra Utilities needs to reverse the adverse trend of failing equipment in these categories by increasing renewal investment in underground XLPE, switchgear and overhead systems. Alectra Utilities has established appropriate and prudent plans to increase system renewal investments in XLPE cables and switchgear, as well as continued investment in overhead system renewal. Alectra Utilities XLPE investments improve on reliability from the 2018 levels as supported by customers in Appendix 1.0 of C02 – 2020-2024 DSP Customer Engagement, and discussed in Appendix A10 – Underground Asset Renewal.

C.2 Work Execution

With respect to Work Execution, Alectra Utilities has established two DSP-specific performance measures. These will enable the company to track performance relative to its Operational AM Strategic Principle of increasing monitoring, analytics and business intelligence capabilities to support operational excellence and continuous improvement. The two work execution metrics enable Alectra Utilities to measure and track its progress in executing all distribution capital and work on-budget and on-time.

Table 5.2.3 - 10: Work Execution Performance Measures

Measure Category	2020-2024 Performance Measure	Historical Performance	Target (2020-2024)
Operational	Cost Performance Index (CPI)	N/A	Monitor
	Schedule Performance Index (SPI)	N/A	Monitor

The two performance measures for work execution are:

Cost Performance Index (“CPI”), measures the company’s ability to complete projects within their established budget. Actual project costs are measured as a ratio of actual to planned estimated costs so to determine the CPI. CPI-related variances are examined for mitigation of cost deviations and continuous operational improvements.

Schedule Performance Index (“SPI”), measures the company’s ability to complete projects within their planned schedule. Actual project duration is measured as a ratio of actual duration to planned duration so to determine the SPI. Alectra Utilities places a high priority on the tracking of SPI for customer connection projects, in support of its commitment to effectively manage and meet customer service obligations, and allow customers to better plan and manage their internal timelines in relation to expected project completion.

The CPI and SPI are new measures introduced after the formation of Alectra Utilities. Therefore, the requisite five years of historical data are not available. Alectra Utilities will measure and track its work execution DSP-specific performance measure over the duration of the DSP implementation period to establish a baseline from which it may in future propose a target.

5.2.3.3 UNIT COST METRICS

Alectra Utilities measures its unit cost metrics in conformance with the Chapter 5 filing requirements, specifically Appendix 5-A. Unit cost measures are based on total cost per customer served, per kilometer of distribution line, and per megawatt of demand.

In addition to total cost, Alectra Utilities considers capital expenditure ("CAPEX") and Operational and Maintenance ("O&M") cost per customer served, and per kilometer of distribution line.

Table 5.2.3 - 11 presents the unit cost metrics of Alectra Utilities for 2018 and the five-year average (2014-2018 inclusive).

Table 5.2.3 - 11: Unit cost Metrics for Performance Measurements

Metric Category	Metric	Measures	
		(2018) 1 Year	2014-2018 (5 Year) Average
Cost	Total Cost per Customer	384	412
	Total Cost per km of Line	19,077	20,215
	Total Cost per MW	74,352	80,809
CAPEX[41]	Total CAPEX per Customer	294	313
	Total CAPEX per km of Line	14,597	15,350
O&M[42]	Total O&M per Customer	90	99
	Total O&M per km of Line	4,480	4,865

As illustrated in Table 5.2.3 - 11, Alectra Utilities has experienced a decline for all unit cost metrics in 2018 compared to the five-year average.

Total Cost per Customer decreased by $28 in 2018 from the five-year average to $384, which represents a 6.8% decrease. Similarly, Total Cost per kilometer of Line and Total Cost per Megawatt decreased by 5.63% and 7.99% respectively.

[41] Information regarding capital expenditures for the 2014, 2015, and 2016 Historical Years is based on the capital plans of Alectra Utilities' individual predecessor utilities, which approached capital spending in a manner specific to their individual needs. This document represents Alectra Utilities' first DSP, and is a comprehensive plan that takes into account and balances system needs across its entire service territory. The historical capital expenditure information has been prepared for purposes of meeting the Filing Requirements by mapping these historical expenditures for the individual predecessor companies to current activities where possible. As the 2014, 2015, and 2016 capital expenditure decisions were not made by Alectra Utilities but, rather, by separate corporate entities, that historical capital expenditure information does not provide an appropriate basis for comparison or from which reasonable conclusions can be drawn. See Appendix P – Historical Capital Expenditures for the historical expenditure data for 2015 and 2016 for each of the five predecessor utilities on an individual basis, which is provided for the sole purpose of satisfying the DSP Filing Requirements.

[42] The 2014, 2015, and 2016 historical O&M expenditure information has been prepared for purposes of meeting the Filing Requirements by mapping these historical expenditures for the individual predecessor companies to current activities where possible. As the operational decisions and approaches underlying the 2014, 2015, and 2016 O&M expenditures were not made by Alectra Utilities but, rather, by separate corporate entities, and were based on different accounting and capitalization policies applied by those entities, that historical O&M expenditure information does not provide an appropriate basis for comparison or from which reasonable conclusions can be drawn.

The unit cost metrics for the CAPEX category experienced a decrease. The Total CAPEX per Customer has decreased by $19 in 2018 from the five-year average to $294 per customer, which represents a 6.1% decrease. Similarly, Total CAPEX per kilometer of Line decreased by 4.9%.

O&M unit cost metrics measured by Total O&M per Customer and Total O&M per kilometer of Line decreased to $90 and $4,480 in 2018 respectively. The decline represents 9.1% in Total O&M per Customer and 7.9% in Total O&M per kilometer of Line from the five-year average.

Alectra Utilities is committed to improving productivity and achieving efficiencies, which will drive cost savings in both capital and Operating, Maintenance and Administrative (OM&A) initiatives. At the same time, it is important to recognize the realities and challenges associated with managing a large portfolio of deteriorating distribution assets in a fast growing service area. Customer and load growth drivers require well-planned infrastructure expansion, which will put upward pressure on O&M costs as a result of new assets being installed, inspected and maintained. At the same time, there are needs for ongoing asset renewal and continuing enhancement and expansion of the Alectra Utilities' inspection, maintenance and data collection activities for existing assets. These activities are part of the continued evolution of the asset management program to support more effective and rigorous decision making. This is crucial given the deteriorating condition of major distribution assets, as well as the largely underground configuration of the Alectra Utilities system, which is generally more costly and challenging to inspect and maintain relative to overhead systems.

5.2.4 REALIZED EFFICIENCIES DUE TO SMART METERS

5.2.4.1 OVERVIEW

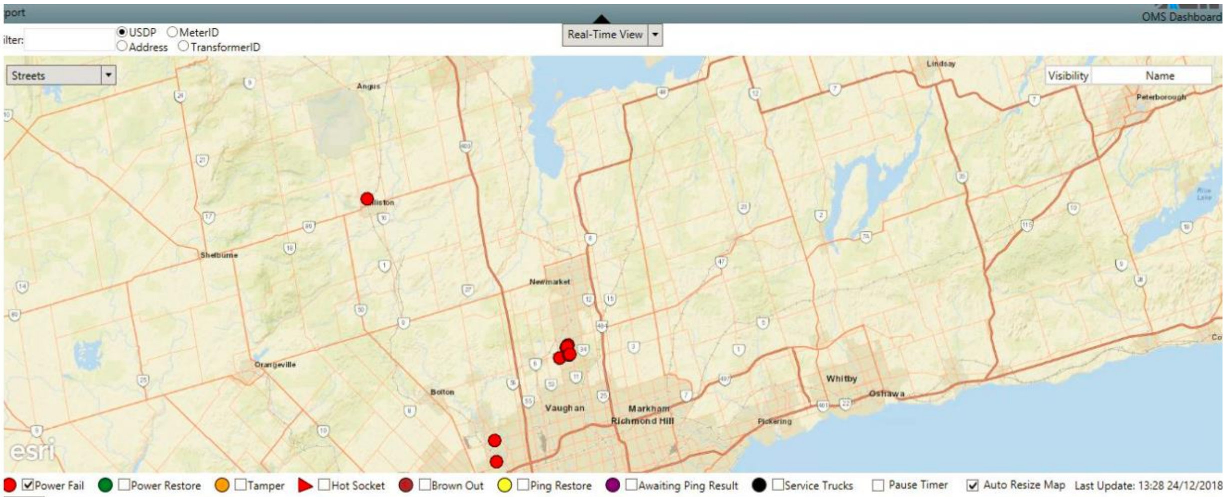
Alectra Utilities has been able to realize a number of operating efficiencies, either from the granular AMI data produced by the system, or by leveraging the AMI platform to develop other operational tools. Without the initial AMI investment, a number of these operating efficiencies would simply not have been possible, or would not have been cost-effective to implement. However, Alectra Utilities does not have quantitative data to show the value of the operational improvements or cost efficiencies realized from the deployment of smart meters or related technologies.

The implementation of operational tools to leverage AMI data for different areas within Alectra Utilities' service territory is at varying stages, with some areas being at a mature state and others less so. Alectra Utilities is implementing an Outage Management platform that will be able leverage AMI data and ensure consistency in the way AMI data is leveraged for outage management purposes across the company's entire service area.

Some of the efficiencies discussed below are derived simply from using the AMI platform. These efficiencies are realized on a daily basis. The AMI platform has also permitted the implementation of other tools that have resulted in further operating efficiencies, as follows.

1. The smart meter "last gasp" functionality used to support Alectra Utilities' Outage Management System ("OMS") continues to be used daily. Multiple simultaneous smart meter "Last Gasp" messages received through the AMI network allow System Control Operators to identify customers experiencing power outages. The smart meter last gasp outage reporting functionality is utilized to provide early detection of an outage, which previously would have depended on a customer calling in to report the outage. This functionality has led to quicker deployment of crews and up to 15 minutes in saved outage restoration time in most cases. The smart meters also assist in locating the common point of failure. Customer outage minutes are reduced with early response and the operators can quickly identify which transformer(s) the customers are connected to using the predictive engine made available by the smart meters. Figure 5.2.4 - 1 provides a snapshot of how the system displays smart meters reporting power failures.

Figure 5.2.4 - 1: Meters Reporting Power Failures



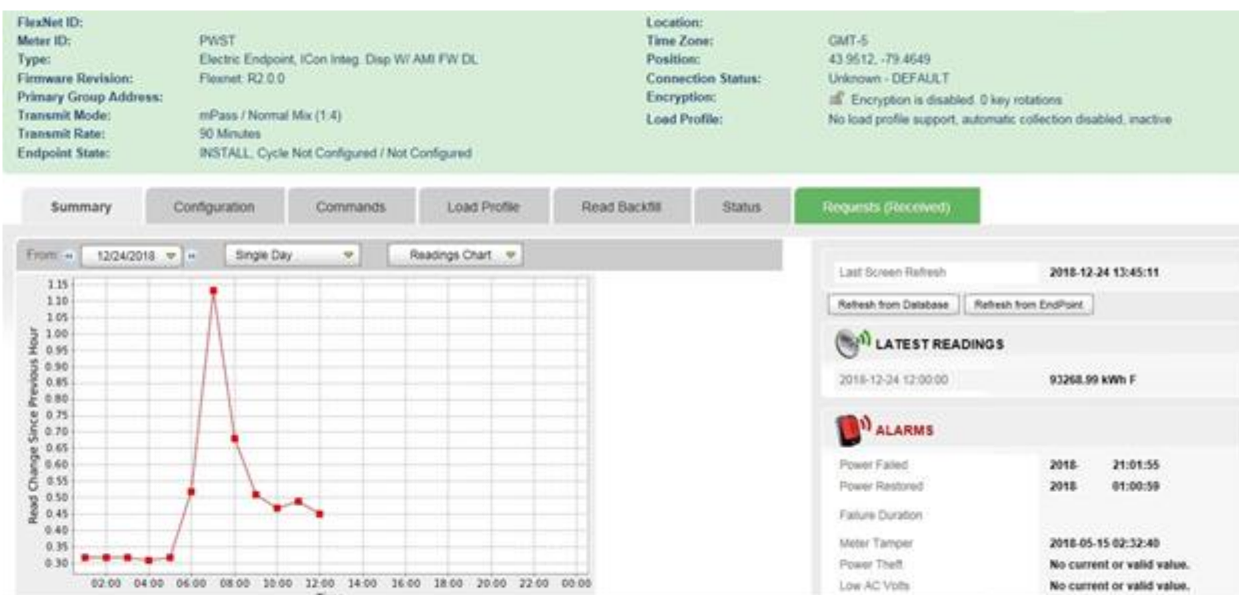
A sampling of historical data from 2014 for Alectra Utilities East operating area where the smart meters were fully deployed indicates that out of 656 incidents reported by the AMI 195 were dispatched within 15 minutes, 455 within 60 minutes and 6 over 60 minutes.

In addition, after restoration the System Controllers have the ability to check if the entire area has been restored by verifying with the meter map that all meters are back on. This has been useful in cases where there was a nested outage within the main outage area. During these events Alectra Utilities has been able to save upwards of 60 minutes of crew dispatch time and trouble truck costs as crews are still on site and can attend to the nested outages.

2. Alectra Utilities has implemented a web-based application that allows it to 'ping' individual meters as well as multiple meters. In the event of a specific field issue, this tool can be used by the Control Room Operators to quickly diagnose whether Alectra Utilities is experiencing a single customer connection issue, or an upstream issue affecting multiple customers. Control Room Operators are therefore able to quickly and remotely diagnose whether a single, or a larger scale outage has occurred and to promptly deploy the appropriate resources or take other measures to resolve the issue. The ability to ping meters helps system control operators to ensure that the entire outage has been corrected and to avoid repeat crew dispatch which results in cost savings and better customer service. This happens infrequently mostly during major storm event days and have resulted in saving of 60 minutes of dispatch time.

3. System Control Operators can read individual smart meters in real time through the AMI to verify whether a customer reporting an outage has a customer side issue or a utility issue while the customer is on the phone. This not only provides better customer service but can also mitigate the unnecessary deployment of trucks and service crews. This feature is available in the Alectra East service area, where the company has been able to defer 473 service calls to customer premises from 2014 to 2018, thereby resulting in savings related to truck rollout and crew deployment. The avoidance of 473 truck rolls for the period is estimated to have had an avoided cost of approximately $0.3MM based on minimum of 2 hours call involving truck roll with 2 lines person assuming that 70% of the calls would have occurred during regular hours and 30% calls during afterhours. Alectra Utilities plans to implement this functionality across the company's entire service area so that it is in a position to realize the same benefits across the remaining 62% of its service territory. Figure 5.2.4 - 2 illustrates the individual meter readout which informs Alectra Utilities the status and the alarms of the meter which is used to troubleshoot the outage.

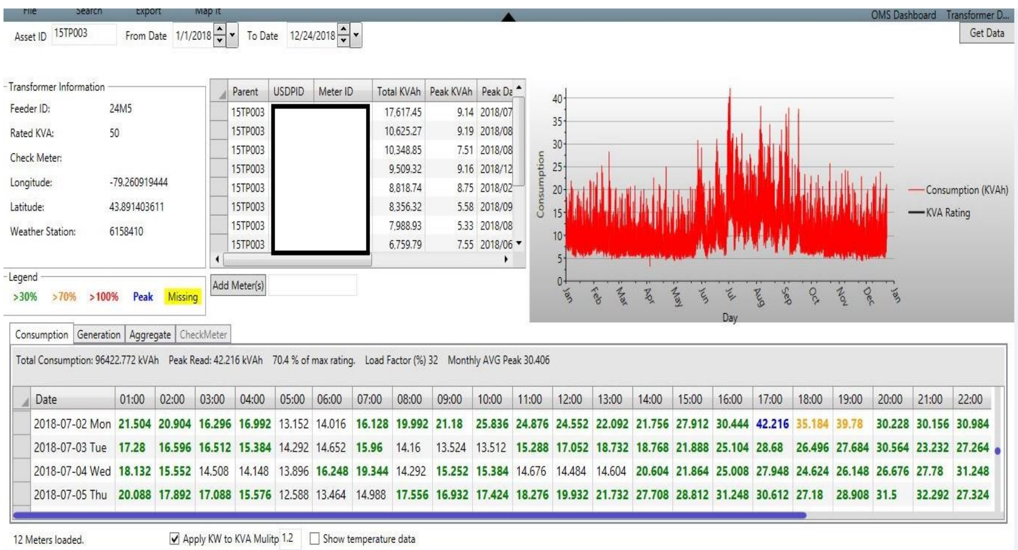
Figure 5.2.4 - 2: Individual Smart Meter Readout



4. Smart meter hourly interval data is used by Alectra Utilities to create detailed transformer load profiles, covering 24-hour, monthly, yearly as well as seasonal load curves. This data set allows the company to identify potentially overloaded transformers so that they can be

replaced in a planned fashion during normal working hours, instead of in response to emergencies or during unplanned outages, thereby providing improved customer service and enhanced cost control. Figure 5.2.4 - 3 shows how individual transformer loading appears to operators. This feature has proven beneficial for system planning as overloaded transformers can be identified and remedial actions taken to avoid failures. This data also provides planners with the ability to right-size transformers during system renewal efforts.

Figure 5.2.4 - 3: Transformer Loading Profile from AMI



5.3.1 ASSET MANAGEMENT OVERVIEW

Alectra Utilities' Asset Management Framework sets the foundation of the DSP, and the basis of all capital investments. Asset Management decision-making is focused on balancing asset performance with the long-term value of the investment. More specifically, the objective of Alectra Utilities' Asset Management Framework is to maintain the lowest possible long-term cost of asset ownership, balancing customer needs and preferences and adhering to electrical system design requirements and standards, construction codes and prescribed asset and manufacturer specifications.

As illustrated in Figure 5.3.1 - 1, the starting point and first component of the Asset Management Framework is Alectra Utilities' Corporate Strategic Goals and Objectives, which guide the establishment of the second component – the company's Asset Management Strategy. In turn, the Asset Management Process, as the third component of the Asset Management Framework, represents the operationalization of the framework in accordance with the Asset Management Strategy.

Figure 5.3.1 - 1: Asset Management Framework

After the formation of Alectra Utilities in 2017, the company worked to develop a harmonized and uniform Asset Management Framework for the consolidated utility, which would underpin the creation of a comprehensive DSP. The DSP includes a capital investment portfolio that incorporates customer preferences and needs, addresses system and operational requirements, is responsive to public policy, and ensures sustainable financial performance.

Customer's needs, priorities, and preferences are central to Alectra Utilities' Asset Management Framework. Before the utility began assessing specific investment options for this DSP, it considered customer needs and priorities**.** Later in the process, once Alectra Utilities identified specific potential investments to satisfy those needs and priorities, it consulted with customers again to seek their preferences on specific investment options. Customer input from this second phase was then reflected in the capital investment optimization process that ultimately produced the investments in the DSP.

Alectra Utilities' Asset Management Strategy was derived from the utility's Corporate Strategic Goals and Objectives, through collaborative workshops with key stakeholders accountable for implementing prudent and effective solutions to achieve these Corporate Strategic Goals and Objectives, which are explained in detail below. The Asset Management team then consolidated legacy Asset Management processes, resulting in a new harmonized, uniform and systematic Asset Management Process to collect, assess, evaluate, prioritize and optimize system and operational needs based on current and future system operating conditions. On this basis, Alectra Utilities is able to ensure that all system and operational needs are appropriately identified and considered for the diverse operating zones across its service area, in alignment with all relevant considerations, including customer preferences and priorities, regional planning requirements, government policy and directives, and Corporate Strategic Goals and Objectives.

5.3.1.1 CORPORATE STRATEGIC GOALS AND OBJECTIVES

In developing the Asset Management Framework, Alectra Utilities started with its Corporate Strategic Goals and Objectives to ensure they are consistently reflected and supported by the resulting Asset Management Strategy and Process. These Corporate Strategic Goals and Objectives are a formulation of the utility's overall vision, mission, and values:

- Corporate Vision: To be Canada's leading electricity distributor and create a future where people, businesses, and communities will benefit from energy's full potential.
- Corporate Mission: To provide customers with smart and simple choices, while creating sustainable value for communities, customers, shareholders and employees.
- Corporate Values: customer focus, innovation, excellence, quality, respect, community and sustainability.

Alectra Utilities' Corporate Strategic Goals and Objectives were established from its parent company Alectra Inc.'s Strategic Plan, which includes certain Corporate Strategic Goals and Objectives that are not relevant to the regulated distribution business conducted by Alectra

Utilities. As such, Alectra Utilities has presented only those Corporate Strategic Goals and Objectives applicable to the distribution business, organizing them in a way that maintains the consistent meaning and purpose of the Goals and Objectives relative to the parent company's Strategic Plan.

Alectra Utilities' Corporate Strategic Goals and Objectives are grouped into the following themes:

- optimizing operations and enhancing the customers' experience, and
- building corporate resilience.

The specific Corporate Strategic Goals and Objectives are summarized in Table 5.3.1 - 1.

Table 5.3.1 - 1: Alectra Utilities' Corporate Strategic Goals and Objectives

Themes:	Optimizing Operations and Enhancing Customer Experience	Building Corporate Resilience
Strategic Goals:	Optimize the operation of assets and related processes and enhance customer experience in a financially prudent manner.	Invest in our people and processes to meet the needs of our customer and stakeholders.
Strategic Objectives:	• Optimize operations and lifecycle management and related processes regarding asset renewal to maintain reliability and customer service levels. • Invest in and leverage emerging technologies to enable operations, maintain reliability, integrate conservation and demand management and distributed generation activities. • Proactively enhance customer engagement and levels of service through levering various channels/technologies. • Maintain and continue to improve upon our strong safety record.	• Service organic growth requirements. • Be a focused, sustainable and flexible organization positioned to succeed in the evolving market, in the energy industry and in the face of increasing extreme weather. • Strengthen the development and engagement of employees. • Continuously optimize business practices and processes to best-in-class performance.

5.3.1.2 ASSET MANAGEMENT STRATEGY

Alectra Utilities' Asset Management Strategy is articulated through the following principles (referenced herein as "Principles" or "Asset Management Principles"):

- <u>Financial</u>:

  - 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.
- Customer:[43]
  - Evolve the distribution system to increase Alectra Utilities' ability to meet current and future customer needs through a range of traditional and emerging solutions.
  - Identify, understand and incorporate customer preferences and priorities to enable the appropriate integration of solutions, products and services on the grid.
- Operational:
  - Enhance operational effectiveness and system performance in alignment with Alectra Utilities' long term plans by balancing the need for system renewal, system modernization and cost mitigation.
  - Prepare the distribution system for new technologies, while controlling costs and optimizing system utilization.
  - Increase monitoring, analytics and business intelligence capabilities to support operational excellence and continuous improvement.
- Regulatory:
  - Ensure alignment between asset management and regulatory requirements and policies, including Ontario's *Long-Term Energy Plan: Delivering Fairness and Choice*.
- Organization:
  - Empower internal resources to innovate and develop flexible solutions.
  - Develop diverse competencies to enable nimble adaptation to change, as driven by fact-based decision making and business intelligence.
  - Leverage and adopt technology solutions to increase collaboration on an enterprise-wide basis and across Alectra Utilities' service area.

[43] Please refer to Section 5.3.1 A.1.1 below for a detailed overview of the process undertaken by Alectra Utilities to address customer needs and preferences.

Alectra Utilities' Asset Management Principles are intended to facilitate the achievement of its Corporate Strategic Goals and Objectives, which, as noted above, fall into two themes: (i) optimizing operations and enhancing customer experience, and (ii) building corporate resilience. Table 5.3.1 - 2 to Table 5.3.1 - 3 below demonstrate the relationship between the Corporate Strategic Goals and Objectives under each theme and the relevant Principles adopted by the utility to support and achieve such Goals and Objectives. As noted above, the utility's Asset Management Principles guide its Asset Management Process, which includes the development and optimization of a Five-Year Capital Investment Portfolio based on specific criteria and considerations that align with relevant Corporate Strategic Goals and Objectives as well as Asset Management Principles (see discussions in Section 5.3.1 below and Section 5.4.1).

Table 5.3.1 - 2: Corporate Theme – Optimizing Operations and Enhancing Customer Experience

Corporate Strategic Goal	Corporate Strategic Objective	RRF Outcome	Asset Management Principle
Optimize the operation of assets and related processes and enhance customer experience in a financially prudent manner.	Optimize operations and lifecycle management and related processes regarding asset renewal to maintain reliability and customer service levels.	Financial Performance	**Financial** - 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.
		Customer Focus	**Customer** - Identify, understand and incorporate customer preferences and priorities to enable the appropriate integration of solutions, products and services on the grid.
		Operational Effectiveness	**Operational** - Enhance operational effectiveness and system performance in alignment with Alectra Utilities' long term plans by balancing the need for system renewal, system modernization and cost mitigation.
	Invest and leverage emerging technologies to enable operations, maintain reliability, integrate conservation and demand management and distributed generation activities.	Customer Focus	**Customer** - Evolve the distribution system to increase Alectra Utilities' ability to meet current and future customer needs through a range of traditional and emerging solutions.
		Operational Effectiveness	**Operational** - Prepare the distribution system for new technologies, while controlling costs and optimizing system utilization.
		Public Policy Responsiveness	**Regulatory** - Ensure alignment between asset management and regulatory requirements and policies, including Ontario's Long-Term Energy Plan: Delivering Fairness and Choice.
	Proactively enhance customer engagement and levels of service through levering various channels/technologies.	Customer Focus	**Customer** - Identify, understand and incorporate customer preferences and priorities to enable the appropriate integration of solutions, products and services on the grid.
		Operational Effectiveness	**Organizational** - Leverage and adopt technology solutions to increase collaboration on an enterprise-wide basis and across Alectra Utilities' service area.
	Maintain and continue to improve upon our strong safety record.	Operational Effectiveness	**Operational** - Enhance operational effectiveness and system performance in alignment with Alectra Utilities' long term plans by balancing the need for system renewal, system modernization and cost mitigation.

Table 5.3.1 - 3: Corporate Theme – Meeting Customer Needs and Building Corporate Resilience

Corporate Strategic Goal	Corporate Strategic Objective	Asset Management Principle
Invest in our people and processes to meet the needs of our customers and stakeholders.	Service organic growth requirements.	**Customer** - Evolve the distribution system to increase Alectra Utilities' ability to meet current and future customer needs through a range of traditional and emerging solutions.
		Operational - Prepare the distribution system for new technologies, while controlling costs and optimizing system utilization.
	Be a focused, sustainable and flexible organization positioned to succeed in the evolving market, in the energy industry and in the face of increasing extreme weather.	**Financial** - 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.
		Operational - Enhance operational effectiveness and system performance in alignment with Alectra Utilities' long term plans by balancing the need for system renewal, system modernization and cost mitigation.
		Organizational - Develop diverse competencies to enable nimble adaptation to change, as driven by fact-based decision making and business intelligence.
		Organizational - Leverage and adopt technology solutions to increase collaboration on an enterprise-wide basis and across Alectra Utilities' service area.
	Strengthen the development and engagement of employees.	**Operational** - Enhance operational effectiveness and system performance in alignment with Alectra Utilities' long term plans by balancing the need for system renewal, system modernization and cost mitigation.
	Continuously optimize business practices and processes to best-in-class performance.	**Operational** - Prepare the distribution system for new technologies, while controlling costs and optimizing system utilization.
		Organizational - Leverage and adopt technology solutions to increase collaboration on an enterprise-wide basis and across Alectra Utilities' service area.

5.3.1.3 ASSET MANAGEMENT PROCESS

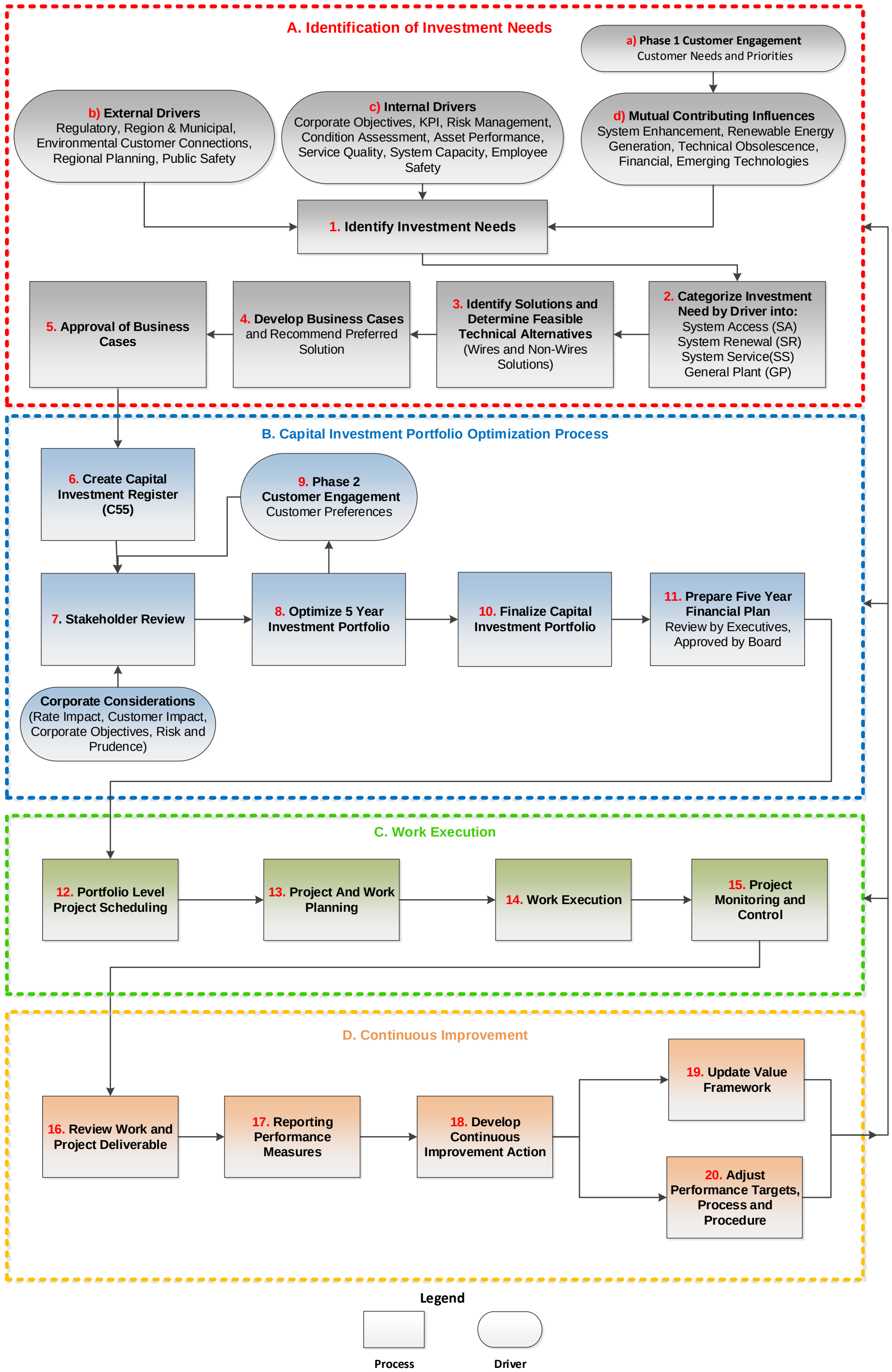
As the third and final component of Alectra Utilities' Asset Management Framework, the Asset Management Process represents the operationalization of the utility's asset management practices, including the assessment of relevant drivers of investment needs, and the development and optimization of investment plans in alignment with, and support of, the aforementioned Corporate Strategic Goals and Objectives and Asset Management Strategy.

The Asset Management Process consists of the following four components, as illustrated in Figure 5.3.1 - 2, below:

- Identification of Investment Needs
- Capital Investment Portfolio Optimization Process
- Work Execution
- Continuous Improvement

1

Figure 5.3.1 - 2: Asset Management Process



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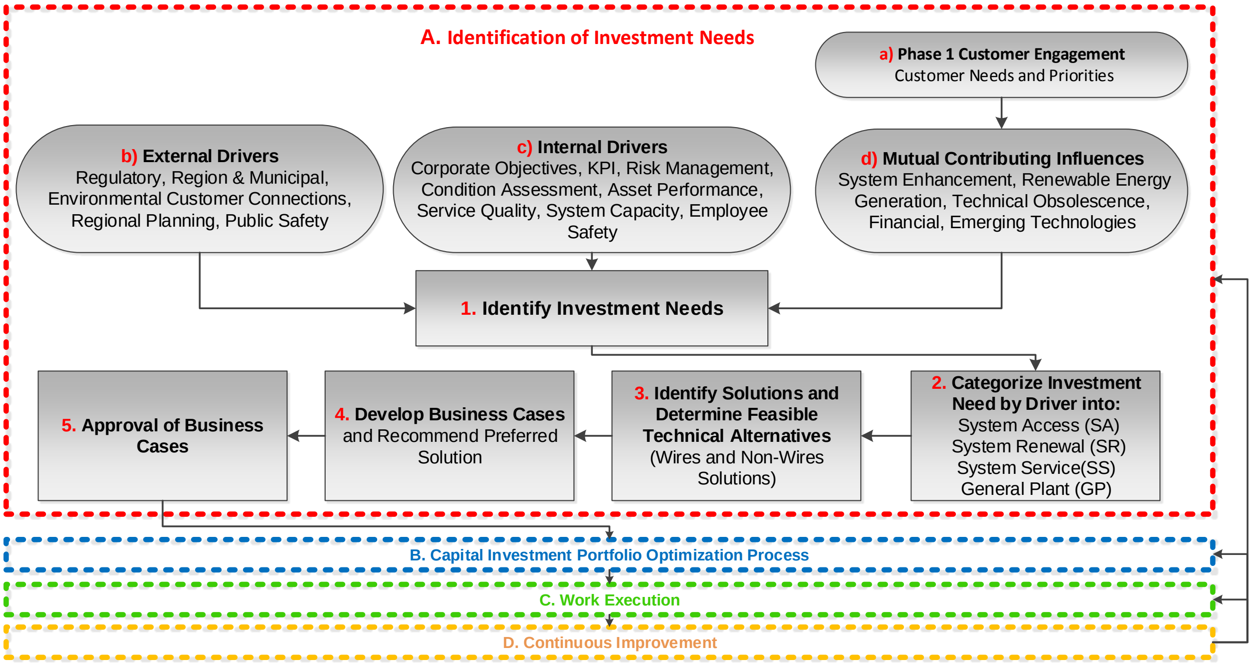
A Identification of Investment Needs

The first component of Alectra Utilities' Asset Management Process is Investment Identification, which is driven in large part by the assessment of investment drivers, including customer priorities and needs, at the outset to determine asset and system needs. Based on the identified drivers and needs, Alectra Utilities develops business cases for potential capital projects and evaluates all candidate projects in a consistent and uniform manner[44]. This ensures that capital investment needs across the entire service area are afforded equal opportunity to be assessed for selection and funding through the final Five-Year Capital Investment Portfolio. As illustrated in Figure 5.3.1 - 3, the main steps of Investment Identification are the following: (i) identify investment needs based on relevant drivers, (ii) categorize investment needs, (iii) identify solutions and determine available technical alternatives, (iv) develop business cases, and (v) approval of business cases.[45]

[44] The term "business case" as used in this section pertains to the documentation of each candidate capital project, including investment drivers and needs, budget estimates, potential alternatives (including recommended approach), and investment value and benefits (e.g., financial, reliability, risk mitigation). As explained in this section 5.3.1 below and in section 5.4.1, these business cases and related workflows (i.e., successive reviews and approvals) are tracked and managed through the utility's investment portfolio software – CopperLeaf C55.
[45] "Approval of business case" in this context refers to the approval of a candidate capital project's business case by the leadership of the relevant business unit. Following approval, the candidate project will be included within the overall, preliminary capital investment portfolio that will then undergo optimization and finalization. For clarity, approval at this stage does not mean the candidate project is selected for execution.

Figure 5.3.1 - 3: Identification of Investment Needs Process



A.1 Identify Investment Needs

Alectra Utilities relies on the assessment of a range of investment drivers to identify potential investment needs across the organization and service area. These drivers are categorized as:

- External drivers, which stem from factors that are generally beyond the utility's management and control, such as service obligations, regional planning requirements, and regulatory compliance;
- Internal drivers, which stem from factors that are generally subject to the utility's management and control, such as corporate objectives, asset condition assessment, and system performance and capacity constraints; and
- Mutual contributing influences, which are drivers that are generally attributable to a combination of external and internal factors. Key mutual contributing influences are the needs and priorities of Alectra Utilities' customers, as identified through ongoing and DSP-specific customer engagement. As summarized in section 5.2.1.5, customer needs and priorities are the foundation of Alectra Utilities' asset management and investment planning activities.

For clarity, while investment needs are ultimately prioritized through the Capital Investment Portfolio Optimization Process, the drivers discussed below are not assigned specific rankings or weight for purposes of evaluating potential investment needs.

A.1.1 Customer Engagement – Phase 1 (Needs and Priorities)

Alectra Utilities engaged Innovative Research Group ("Innovative Research") to assist in undertaking customer engagement specifically to support the development of the 2020-2024 DSP. With assistance from Innovative Research, Alectra Utilities completed two customer consultations for this purpose.

The first consultation was to assess customers' needs and priorities, which informed the investment options that Alectra Utilities identified for the 2020-2024 period. This was conducted in mid-2018 and Innovative Research delivered its findings (in the form of a summary "placemat") in September 2018.[46] Innovative Research's overall finding was that, despite price concerns, customers are generally willing to consider paying more to maintain a reliable system. Please refer to Section 5.2.1.5, Part C for a detailed explanation of the methodology and outcomes from the placemat consultation. Based on customers' input and other Corporate Objectives, Alectra Utilities prepared a preliminary set of potential investment portfolios for the 2020-2024 period. The results of the first consultation directly informed and influenced the identification of investment needs and decision-making throughout the Asset Management Process.

The placemat engagement indicated to Alectra Utilities that although customers are satisfied with the current service, the top needs identified were either "nothing" or "lower rates". To reflect the concerns of rates, Alectra Utilities developed several solutions to mitigate the need for system expansion and renewal of substation assets. As explained in more detail in Section 5.4.3, Alectra Utilities developed solutions to mitigate the need to rebuild or construct new stations by enhancing the use of monitoring technologies, investing in environmental protection measures and strategically managing inventory on a consolidated basis. Alectra Utilities plans to focus investment on renewing key equipment that is associated with controlling, monitoring and

[46] The placemat is attached as Appendix C01 - Placemat – First Phase of Customer Engagement.

protecting core system assets, which equipment is deteriorated, obsolete and which adversely affects reliability. In addition, investments in monitoring equipment, along with investments in oil spill containment, will give rise to significant capital savings by enabling the company to defer station renewal investments. Monitoring solutions provide operators with more real-time data, which can be used to proactively manage performance through maintenance and to better identify when and where station rebuilds or equipment replacements are necessary. Spill containment systems enable the company to defer transformer replacements as Alectra Utilities mitigates the risks of environmental oil contamination and costly remediation. Without containment, Alectra Utilities would be required to replace the transformers sooner.

In addition to mitigating the need to renew station assets, Alectra Utilities developed plans to mitigate the strain on the system caused by expansion of growth. This will be done through establishing additional feeder ties between legacy systems and balancing loads across its entire service area. Alectra Utilities plans to make targeted investments in establishing additional connections between adjacent legacy systems to assist the company in balancing loads more effectively; thus, deferring the need for most of the costly system expansions.

Based on customer input, Alectra Utilities understands that, despite price concerns, customers are generally willing to consider paying more to maintain a reliable system. In order to assess and address this customer input, Alectra Utilities examined the factors driving the deteriorating trend in reliability and determined that outages due to defective equipment, specifically failing underground system assets, were the leading contributors. In order to reverse this trend and maintain reliability levels, Alectra Utilities examined remedial alternatives and developed solutions based on cable replacement and cable rehabilitation (using silicone injection technology) as potential investments.

Alectra Utilities' customers indicated that reducing the length of outages due to extreme weather events was a high priority. In order to address this customer input, Alectra Utilities examined the factors driving the increasing trend in outages due to adverse weather conditions and determined that specific sections and equipment of the overhead system and stations were vulnerable to catastrophic failure and prolonged outage durations in adverse weather conditions. In order to reverse this trend and maintain reliability levels, Alectra Utilities examined remedial alternatives and developed solutions based on overhead system rebuild and addressing station facilities installed below ground level and prone to flooding.

A.1.2 External Drivers

External drivers primarily stem from Alectra Utilities' obligations toward customers, the public, and other external stakeholders. As detailed in Table 5.3.1 - 4, these drivers give rise to mandatory investments that must be undertaken by Alectra Utilities to meet regulatory and legal requirements, accommodate externally driven projects, meet customer service obligations, align with regional planning needs, and ensure environmental integrity and public safety.

Table 5.3.1 - 4: External Drivers

External Source	Investment Need Driver Description
Regulatory	• • Compliance with regulatory requirements, including applicable codes, license conditions, design standards, and Electrical Safety Authority ("ESA") requirements. • Public policy responsiveness. • Investments to ensure regulatory compliance are mandatory.
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. • Investments to meet governmental requirements are mandatory.
Environmental	• Compliance with environmental obligations pursuant to applicable standards and requirements of public and government agencies. • Investments to ensure environmental compliance are mandatory.
Customer Connections	• Obligation to accommodate requests for connections of residential, industrial or commercial customers. • Investments to connect customers are mandatory.
Regional Planning – Integrated Regional Resource Plan ("IRRP") and Regional Infrastructure Plans ("RIP")	• Investment drivers stemming from the outcomes of regional planning activities. • Investments to meet regional planning requirements are mandatory.
Public Safety	• Obligation to identify and remediate hazards to minimize risks and impact to public safety. • Investments to ensure public safety are mandatory.

A.1.3 Internal Drivers

Internal drivers of investments include Corporate Strategic Objectives, system performance issues and risks, asset condition, capacity constraints, and employee safety concerns, as outlined in Table 5.3.1 - 5:

Table 5.3.1 - 5: Internal Drivers

Internal Source	Investment Need Driver Description
Corporate Strategic Goals and Objectives	• Alignment with Alectra Utilities' Corporate Strategic Goals and Objectives (see Table 5.3.1 - 1), including the commitment to meet the needs and requirement of the utility's customers.
Performance Measures (i.e. Key Performance Indicators) / Service Quality	• Performance Measures and Service Quality targets (see Section 5.2.3).
Risk Management	• Investments to mitigate identified and unacceptable level of risks related to compliance, system capacity, safety, environmental, financial, reputational and information technology capacity. (see Section 5.4.1).
Condition Assessment	• Distribution asset health as determined from asset register data, asset inspection findings, and asset condition assessment. • Fleet asset condition based on deterioration, repair history, service reports, mileage, engine hours, etc. • Building and property condition. • Investment needs relating to IT assets (including servers, printers, plotters, and communications systems).
System Capacity	• Need for transformation and distribution capacity expansions based on short, medium and long-term distribution system planning requirements. • System planning criteria relating to annual peak loading.
Asset Performance (Reliability)	• Trends and issues with respect to reliability performance indices and metrics. • Worst-performing feeders and associated remedial needs.
Employee and Public Safety	• Capital investments arising from the ongoing review, development and updating of safety-related policies and procedures. • Required new infrastructure/equipment to eliminate unsafe conditions. • Initiatives in response to specific safety-related issues or industry innovations.

More specifically, a number of internal systems and analytical studies underpin the tracking and derivation of data that inform relevant internal drivers, including asset data registers, asset condition assessment, capacity/utilization assessment, and reliability performance studies, as discussed below:

A.1.3.1 Internal Driver Input – Asset Data Registers

This section highlights the various inputs, registers and systems that inform internal drivers of investment needs under Alectra Utilities' Asset Management Process. Collectively, asset registers refer to the repositories that house all relevant information regarding Alectra Utilities' diverse asset base. The following key systems are used to acquire, organize, update and maintain these registers, as further explained below:

- Supervisory Control and Data Acquisition ("SCADA") system;
- Geographical Information System ("GIS") system;
- Outage Management System ("OMS");
- Cascade system;
- Station drawing repository;
- FileNexus;
- ServiceNow Computer Information system;
- Fleet Management systems; and
- Facilities Management systems.

Through these tools, Alectra Utilities collects and tracks data regarding its distribution and non-distribution assets. While different asset registers inform and help define the internal drivers of investment needs, Alectra Utilities structures and evaluates business cases according to a uniform value framework to ensure consistency and commonality across the Asset Management Process and associated investment decisions.

SCADA System

Alectra Utilities' SCADA system provides real-time data on key field assets (e.g., stations, automated switches, wholesale smart meters, etc.). Real-time monitoring of key assets enables System Control Operators to observe asset status, control performance and configure the distribution system to optimize performance as well as the supply of power to customers. Data that is typically collected through the SCADA system includes equipment status (on/off), current flow (amps) and alarms related to mission-critical station equipment (relay triggers). SCADA stores historical and archived data (e.g., feeder loading data) which is utilized for engineering and operational analysis (e.g., System Adequacy Assessment). Alectra Utilities utilizes its SCADA system to obtain data used as input into system utilization and capacity analysis, which are crucial internal drivers for the Asset Management Process.

Geographical Information System ("GIS")

Alectra Utilities' GIS captures location and attribute data from multiple sources for each electrical distribution asset, providing an accurate record of the entire distribution network and its connectivity. This data is available internally, and many departments rely on the data to meet operational, maintenance and design requirements. GIS data can be queried and extracted to satisfy specific requests for information, such as those related to electrical asset connectivity, age of assets, easements, inspection and testing records, and other asset data.

Approximately 70 percent of the input to Alectra Utilities' GIS originates from capital work involving asset additions. Examples include drawings for new subdivisions, new commercial and residential installations, and capital works for road authority projects.

The remaining 30 percent stems from: operational sources (e.g., open points on feeders, discrepancy verification); maintenance sources (e.g., attribute information arising from inspection or maintenance); and other discrete sources (e.g., joint use, street lighting, land base, orthographic imaging.).

Alectra Utilities uses its GIS system to obtain asset inspection and attribute data used as input into the Asset Condition Assessment, a principal internal driver of system renewal needs in the Asset Management Process.

Outage Management System ("OMS")

Alectra Utilities' OMS performs the function of identifying, tracking, reporting on and assisting in the restoration of power outages. In doing so, OMS uses the GIS connectivity model and inputs from smart meters, SCADA, Customer Information System ("CIS"), Interactive Voice Recognition ("IVR") and manual input to provide a dynamic system and outage information and status. All input on outage calls, whether collected automatically (e.g., from smart meters) or manually, is grouped together to provide a dynamic picture of Alectra Utilities' distribution network performance, including real-time outage notification alerts and reliability statistics. Accordingly, asset performance reports (e.g., operations performance reports) are produced regularly for senior management review. Alectra Utilities utilizes its OMS system to obtain system outage data used as input for system reliability and worst feeder performance analysis, which are the principal internal drivers for the Asset Management Process. Please refer to 5.2.3 for a detailed explanation of how Alectra Utilities incorporates system reliability performance trends in identifying system investment needs.

Cascade System

Alectra Utilities' Cascade system is a Computerized Maintenance Management System which enables the company to implement efficient and timely maintenance of substation assets (e.g., transformers, switchgear, circuit breakers and relays). Alectra Utilities updates the Cascade system with station-related real-time operational data (e.g., from SCADA), as well as from inspections, equipment tests and equipment diagnostics. Station asset attributes are efficiently documented by crews using handheld devices and computer notebooks. These allow for the electronic sharing of operational data to and from Cascade. Advanced algorithms in Cascade generate preventative maintenance orders and alerts based on operating conditions. Cascade provides key station asset attribute data as an input for the utility's Asset Condition Assessment of station assets, a principal internal driver into the Asset Management Process.

Station Drawing Repository

Alectra Utilities' Station Drawing Repository ("SDR") electronically stores engineering reference drawings, including draft drawings, construction drawings, "as-built" drawings and archived (superceded) drawings. The company's Network Services and Network Operations divisions rely on these drawings for their day-to-day work and access them through a file management system. More specifically, the SDR stores drawings of:

- systems (e.g., telecommunications);
- transformer stations (civil, mechanical, wiring and electrical);
- municipal stations (civil, mechanical, wiring and electrical); and
- control centres (layout and schematics).

The Stations Design department manages the SDR, maintaining strict control over the process to add, modify, or delete drawings. By maintaining a common set of electronically stored drawings, accessible only through this managed database, Alectra Utilities ensures the accurate and efficient creation, editing, and modification of drawings. The SDR system provides key attribute data for system and control centre assets as an input for the utility's Asset Condition Assessment, a principal internal driver of Alectra Utilities' Asset Management Process.

FileNexus

Alectra Utilities' FileNexus system is a data repository containing line-related project construction drawings (i.e., for new services, new subdivisions, line relocations and line rehabilitations). For the company's Design, Construction and Operations groups that rely on this data for their day-to-day work, FileNexus serves as a common repository to access all approved and as-built drawings and related project documents. Each type of work and stage of project progress has an established process flow that must be followed for adding, modifying, and deleting drawings. FileNexus enables the utility to track line-related construction work, which is important information for the assessment of investment needs via the Asset Management Process.

ServiceNow Computer Information Systems

As Alectra Utilities' Information Technology Service Management system, ServiceNow provides a harmonized asset management system to manage software/hardware tracking, licensing, and compliance, in the following ways:

- Software: ServiceNow tracks software applications and versions installed across its network. The data is used to reconcile the number of permitted licenses by vendors for compliance and renewal purposes.
- Hardware: ServiceNow tracks Alectra Utilities' IT hardware assets across its network. Some hardware assets are not auto-discoverable on the network (e.g., monitors, telephones), but are nonetheless tracked individually using ServiceNow.
- Configuration Item ("CI") / Configuration Object Inventory ("COI"): ServiceNow manages specific details, dependencies, and relationships within the utility's IT architecture. For example, Alectra Utilities' email system has complex interrelationships and configuration among a number of assets, including hardware, software, and proprietary information (e.g., email data). Accordingly, a CI/COI captures a complete asset that represents "more than the sum of its parts" and is used to manage system changes.

Alectra Utilities utilizes its ServiceNow system to obtain information technology asset data used as input to determine information technology renewal investments, a principal internal driver of general plant investment needs in the Asset Management Process.

Fleet Management Systems

Alectra Utilities uses multiple fleet management systems, as well as its Enterprise Risk Planning system, to track all key fleet asset-related data and attributes, which underpin the development of fleet investment plans. Such data includes:

- assigned preventive maintenance schedule;
- mandatory annual, semi-annual, and quarterly inspections (as per regulatory and industry standards);
- current fleet age and repair history; and
- mileage.

Alectra Utilities utilizes its Fleet Management Systems to obtain fleet asset data used as an input to determine fleet renewal investments needs, a principal internal driver of general plant investment needs in the Asset Management Process.

Facilities Management Systems

Alectra Utilities uses multiple facilities management systems, tools and as well as its ERP system, to track significant facilities asset-related data and attributes, which underpin the development of facilities assets replacement schedules and budgets. Specifically, Alectra Utilities leverages this data to:

- Support facility asset condition assessments,
- Track and monitor facility asset maintenance activities and schedules to identify trends,
- Derive long term facility asset renewal plans, and
- Store routine inspection results conducted by employees and third-party service providers to ensure systems reliability and regulatory compliance.

Alectra Utilities utilizes its Facilities Management Systems to obtain facility asset data used as input to determined facility renewal investments needs, a principal internal driver of general plant investment needs in the Asset Management Process.

A.1.3.2 Internal Driver Input – Asset, System and Reliability Assessments

In addition to the inputs derived from the above-described asset registers, internal drivers of investments are also informed and defined by assessments relating to asset condition and system capacity, as discussed below.

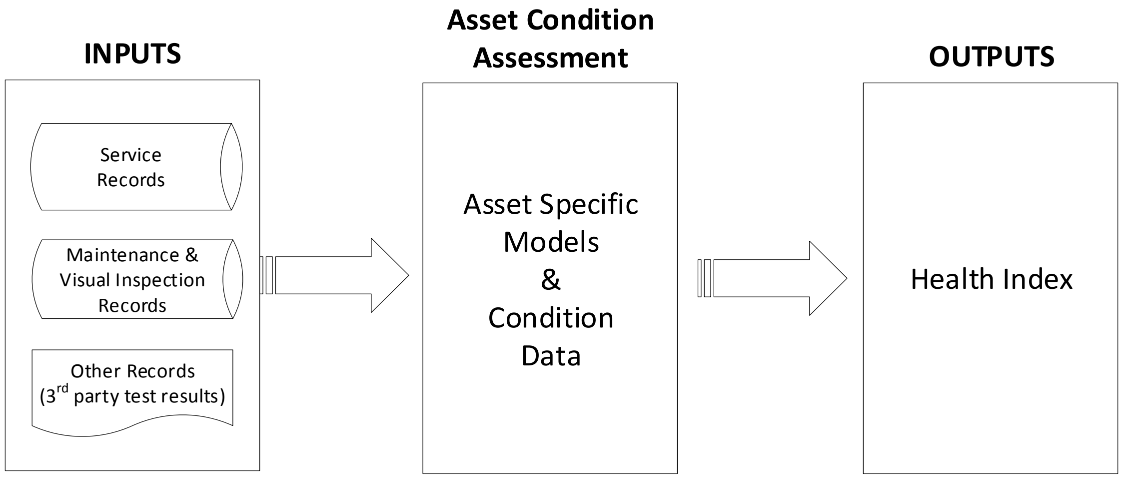
Asset Condition Assessment

This section of the DSP outlines Alectra Utilities' Asset Condition Assessment ("ACA") for distribution assets. The ACA for non-distribution assets (i.e., General Plant assets) is discussed in section 5.4.3.

ACA is the process of analyzing data from multiple sources to assess the condition of distribution assets. Relevant data includes asset demographics, third-party testing programs, and field inspections. Alectra Utilities utilizes the ACA as the basis for developing renewal investments and making fact-driven, pragmatic investment decisions. ACA is an essential tool for ensuring that Alectra Utilities' distribution system does not deteriorate in reliability or pose safety hazards to the public and workers.

In 2018, Alectra Utilities conducted a consolidated and harmonized ACA for distribution and station assets. The ACA applied computational models to input data to determine the assets' Health Index. The HI provides a quantitative indication of asset condition in a consistent manner across each of Alectra Utilities' predecessor utilities. Alectra Utilities' ACA reflects the integration of multiple data sources and the adoption of a common evidence-based framework, as illustrated in Figure 5.3.1 - 4.

Figure 5.3.1 - 4: Health Index Methodology: Inputs, Computation, and Outputs



Each asset class is analyzed using a specific HI model, based on weighted inputs that quantify asset condition in a consistent manner. The number and type of inputs vary by asset class and are determined by available data and industry guidelines.

The advantage of an evidence-based HI is the ability to gauge asset condition using a practical and uniform analytical method. Having a standardized model ensures that all assets are assessed in a consistent manner to guide asset management strategies and policies. The HI inputs, models and results are stored and shared with subject matter experts ("SMEs").

The complete document, is attached as Appendix D - Asset Condition Assessment – 2018.

Asset Capacity/Utilization Assessment

Alectra Utilities developed its current approach for assessing distribution and generation capacity after a comprehensive review of the relevant practices and policies of its predecessor utilities. In order to effectively account for service reliability, costs and risks on a consistent basis, Alectra Utilities identified best practices for universal application across all rate zones, subject to certain limitations due to legacy system constraints. This harmonized approach entails practices, guidelines and criteria that are fundamental to ensuring the timely expansion of Alectra Utilities' distribution system to meet customer load growth and contingency requirements.

Alectra Utilities employs 11 principles for planning the distribution system and determining the capacity thresholds that trigger expansion investments, as discussed below:

1. 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 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 (summer peak) to a maximum loading that isthe 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 (“DESN”) 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 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.

10. Alectra Utilities will maintain a spare transformer (i.e., a mobile unit with multiple primary and secondary configurations) to mitigate the risk of a prolonged station transformer loss.
11. Alectra Utilities will limit the construction of four-circuit pole lines by using two separate double-circuit pole lines on both sides of a roadway, with switching ties for back-up. Where dual pole lines are not permitted, Alectra Utilities will pursue the strategic placement of switching ties and concrete poles, or where prudent, the undergrounding of the feeders.

Capacity Planning and Assessment

Alectra Utilities regularly monitors and assesses short-term and long-term system capacity, primarily through its annual load forecasting process and system adequacy assessment studies. The process also includes Alectra Utilities' ongoing coordination of and participation in regional planning activities and generation connection assessments, together with Hydro One Networks Inc. ("HONI") and the Independent Electric System Operator ("IESO"). Please refer to Section 5.3.2 for a detailed outline of system capacity assessment and Section 5.2.2 for a summary of completed and ongoing regional planning activities.

Load Forecast and System Adequacy Assessment

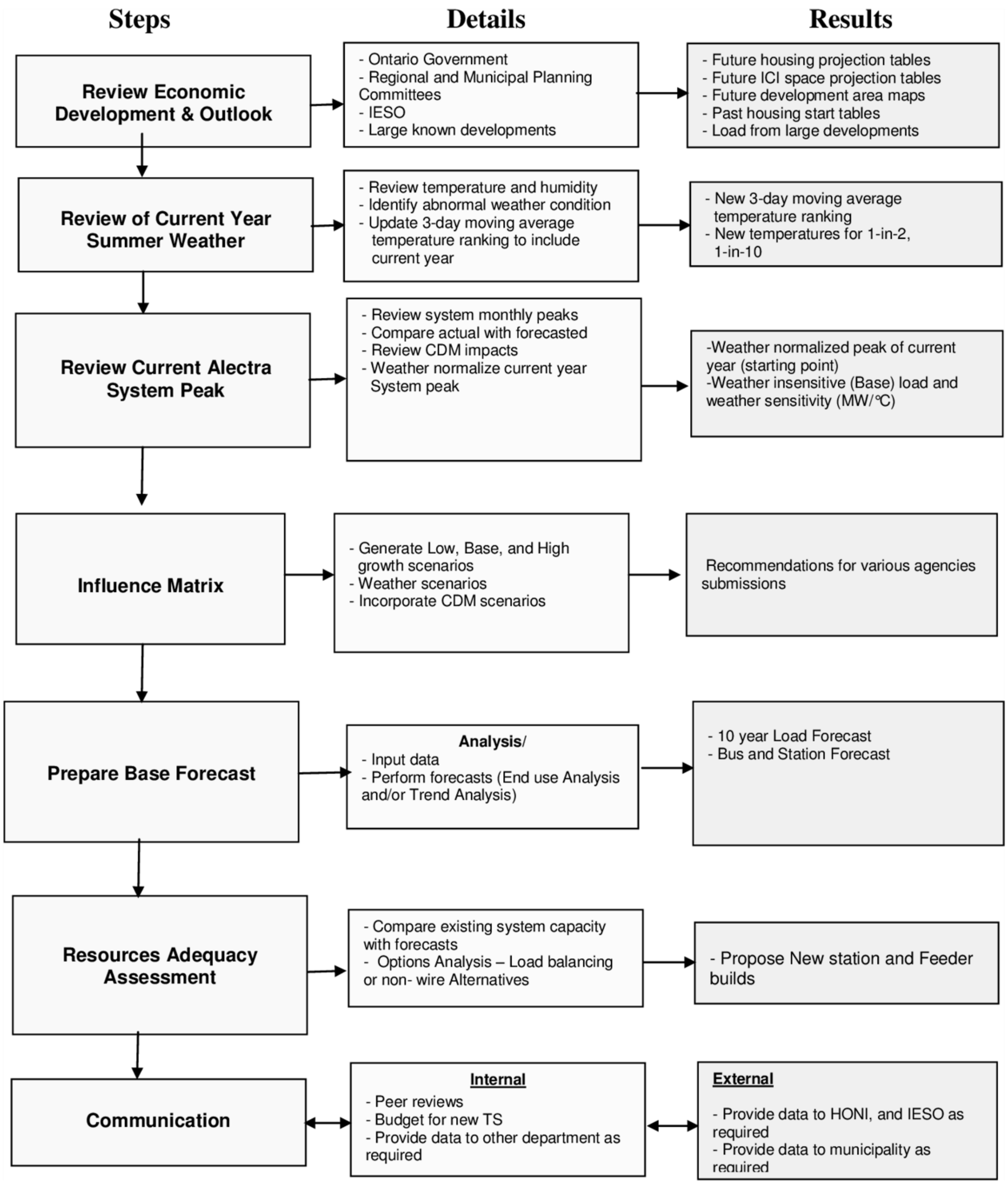
Load Forecast

Alectra Utilities produces an annual load forecast to reflect both short and long-term load growth. The load forecast provides an important indication as to areas where additional capacity will be required, including in connection with the need to account for contingency scenarios, storm impact, and loss of supply.

Alectra Utilities is a summer peaking utility. Its load forecast is representative of normalized weather conditions (extreme weather scenario is assumed once in every 10 years, and normal weather is assumed once in every 2 years), historical load patterns, and expected service growth based on the long-term growth plans of customers and regional and municipal governments. The load forecast methodology also considers other relevant factors, such as the expected impact of Conservation and Demand Management (“CDM”) programs, Distributed Generation (“DG”) and/or rate pricing structures or incentives.

Figure 5.3.1 - 5 illustrates Alectra Utilities’ load forecast process.

1 **Figure 5.3.1 - 5: Load Forecast Process**



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System Adequacy Assessment

After completing the load forecast, Alectra Utilities conducts a system adequacy assessment for its stations and feeders to ensure they can meet the projected load growth and any contingency conditions. In alignment with applicable planning criteria, this assessment takes into account currently available capacity and future needs in order to arrive at identified needs and measures for capacity expansion.

Capacity Risk Mitigation

As summarized below, Alectra Utilities mitigates capacity-related risk through system reconfiguration and load transfers, equipment enhancements, and station or feeder expansion projects:

- **System Reconfiguration and Load Transfers**: Where feasible based on Alectra Utilities' analysis, system reconfiguration and load transfers are generally preferred as the most cost-effective means of addressing the capacity shortfall.
- **Equipment Enhancement**: If system reconfiguration or load transfers cannot solve the capacity shortfall, Alectra Utilities conducts an analysis to determine if increasing the rating of equipment may be a feasible solution, either at the stations (e.g., retrofitting transformers with fans) or on the lines (e.g., line replacement to increase ampacity).
- **Station or Feeder Expansion Projects**: If the capacity shortfall cannot be addressed by the above solutions, Alectra Utilities would consider investment in stations and/or feeders. Localized demand can generally be addressed by substation expansions, which 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 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 A12 - Lines Capacity Investment Summary and A13 - Station Capacity Investment Summary.

<u>Generation Connections</u>

From their inception, electric distribution systems have been planned, designed and constructed to serve loads with effective monitoring and protection. These systems were not constructed to be able to connect with and manage a large number of distributed generators. Accordingly, the amount of generation capacity that can be connected to the distribution system is constrained by a variety of 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.

Relevant assessments indicate that twelve of twenty-two HONI-owned stations are constrained and cannot be connected to additional sources of renewable generation. However, apart from these stations, there is sufficient capacity on Alectra Utilities' distribution system to accommodate expected renewable generation projects. Additional details are found in Section 5.3.4.

Assessment of System Reliability Performance

Please refer to 5.2.3 for a detailed explanation on the process Alectra Utilities uses to assess system reliability performance and how such performance trends inform and drive investment needs.

A.1.4 Mutual Contributing Influences

Mutual Contributing Influences refer to investment drivers that are attributable to both internal and external factors, as provided in Table 5.3.1 - 6.

Table 5.3.1 - 6: Mutual Contributing Influences

Mutual Contributing Influence	Driver Description
Customer Needs and Priorities	• Customer engagement to identify and understand customer needs and priorities regarding a wide range of services provided by Alectra Utilities. • Incorporation of customer needs, priorities and related input in the development of the DSP.
System Enhancements	• Continuous improvements, including through the adoption of more efficient processes and technological solutions.
Renewable Energy Generation	• Infrastructure upgrades to enable service connections of Renewable Energy Generation ("REG") projects.
Technical Obsolescence	• Replacement of obsolete equipment (e.g. assets that no longer receive vendor support).
Financial	• Prudent economical investment to minimize costs.

As described above and in section 5.2.1.5, customer needs, priorities and preferences are the foundation of Alectra Utilities' asset management process. For more details on the role that customer engagement played in developing the capital plan in this DSP, please refer to those sections and to the specific capital investment summaries in Appendices A01 through A20.

A.2 Categorize investment Need by Driver

Pursuant to the OEB's Filing Requirements for Electricity Distribution Rate Applications, Alectra Utilities' overall investment portfolio is categorized into four investment categories:

- **System Access ("SA"):** Investments to modify the distribution system, based on the utility's obligation to accommodate customer connections and comply with other mandated service requirements.
- **System Renewal ("SR"):** Investments to replace assets or refurbish assets to extend service life.
- **System Service ("SS"):** Investments to modify the distribution system to meet operational objectives and future customer requirements.

- **General Plant ("GP"):** Investments to modify, replace, or add non-distribution assets to support the utility's ongoing operations (e.g., facilities, fleet, information technology, etc.)

A.3 Identify Solutions and Determine Feasible Technical Alternatives

To develop candidate projects or initiatives in response to each investment need, Alectra Utilities' Asset Management Process involves the consideration and balancing of a range of inputs, as set out below. The process also entails the consideration of alternative solutions, including non-wires solutions, for each project or initiative, taking into account the cost and benefit of each feasible alternative in terms of its expected risk mitigation potential.

- Asset register data;
- ACA criteria and results;
- Asset capacity utilization/constraint assessments;
- Inspection and maintenance data;
- Asset planning criteria;
- Standards-related needs;
- Safety-related needs;
- Reliability performance;
- Worst-performing feeder analysis;
- Analysis of feasible technical alternatives and project options (see below);
- Customer needs and preferences;
- Input from interdepartmental committees; and
- Cost and benefit assessment.

A.4 Develop Business Cases

After considering and identifying the technically feasible alternatives, Alectra Utilities develops a business case for each candidate project to ensure that proposed investments are prudent, justified based on value, scoped and documented in relation to the expected outcome, timing and customer benefits. For investment needs where no feasible technical solution is available, Alectra Utilities ensures that the relevant need or risk identified through its investment needs analysis is nevertheless mitigated through alternative approaches, including ongoing monitoring, inspection, transfer of risk (i.e., procurement of warranty or insurance) or other appropriate risk management solutions.

Based on the analysis of potential alternatives through the business case development process, Alectra Utilities selects and documents the preferred option that is expected to deliver the maximum total value as defined by Alectra Utilities' Value Framework, which is explained in detail in Section 5.4.1. Alectra Utilities determines the value of each candidate project with the aid of the Copperleaf C55 software system, based on applicable Value Framework parameters (also referred to as Value Functions) and comprehensive project inputs. All projects are valued (and subsequently optimized, as outlined below and further described in detail in Section 5.4.1) based on a Value Function, which weighs a number of Value Measures aligned to Alectra Utilities' Corporate Strategic Objectives and Corporate Risk Matrix (please refer to Section 5.4.1 for an explanation of the Corporate Risk Matrix). As presented in Table 5.3.1 - 7, Value Measures include benefits (e.g., Financial, Reliability, Customer Service), costs (OM&A Costs, Project Cost) and risks (e.g., Financial, System Capacity, Safety).

Alectra Utilities utilizes the Value Function to establish each candidate project's contribution toward the company's Corporate Objectives. Specifically, Alectra Utilities leverages benefit-and-risk questionnaires designed to quantify the value of each applicable measure for every candidate project. The questionnaires are reviewed by Alectra Utilities Asset Management team and business units to ensure appropriate alignment with Corporate Objectives. Table 5.3.1 - 7 below shows the mapping of Value Measures (which form part of the Value Function) in relation to the utility's Corporate Objectives and Risks.

Table 5.3.1 - 7: Mapping of Value Measures to Corporate Objectives and Risks

Value Measure Category	Value Measure	Corporate Objective/Risk
Financial	Capital Financial Benefit OM&A Financial Benefit OM&A Costs Financial Risk IT Capacity Risk Project Cost	• Optimizing Operations and Enhancing Customer Experience • IT Capacity Risk • Financial Risk
Reliability	Distribution System Capacity Risk Reliability Benefit Reliability for Spares Benefit	• Meeting Customer Needs • Optimizing Operations and Enhancing Customer Experience • Distribution System Capacity Risk
Safety	Safety Risk	• Safety Risk
Compliance	Compliance Risk	• Compliance Risk
Customer Service	Customer Communication Benefit Customer Service Benefit	• Meeting Customer Needs • Optimizing Operations and Enhancing Customer Experience
Environment	Environmental Improvements Benefit Environmental Risk	• Meeting Customer Needs • Optimizing Operations and Enhancing Customer Experience • Environmental Risk
Regulatory	Application Ready Organization	• Ensuring Compliance Risk
Public and Employee Perception	Reputational Risk Employee Wellness	• Reputational Risk • Building Corporate Resilience
Innovation	Technological Innovation Benefit	• Optimizing Operations and Enhancing Customer Experience

In addition to scoring projects through the Value Function (i.e., capturing benefits and risks), Alectra Utilities incorporates the following details into its capital funding requests and business cases for further review and approval:

- the specific objective(s) to be achieved;
- background information on the current state of the asset(s) involved;
- detailed analysis of the status quo, including the risk of not maintaining that status quo;
- review of possible alternatives (including financial analysis for each feasible alternative)
- detailed review of the preferred option (i.e. the value it brings and why it was chosen); and
- project duration and schedule.

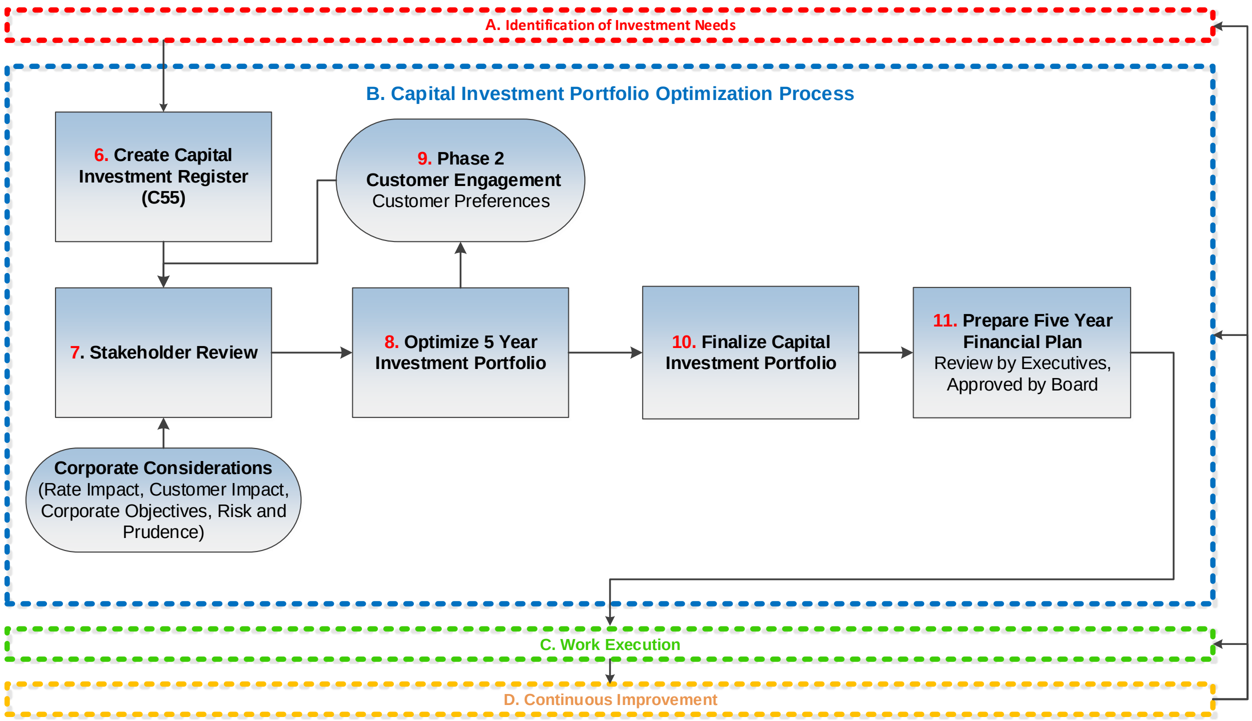
A.5 Approval of Business Cases

Once a designated project lead initiates the CopperLeaf C55 business case approval workflow process, the software system sends an automatic notification that the business case is ready for review in accordance with the utility's investment approval process**.**

B Capital Investment Portfolio Optimization

As shown in Figure 5.3.1 - 6, steps 6 through 10 demonstrate the process that Alectra Utilities applied to establish and optimize the capital investment portfolio that will be submitted for final approval by the Executive Management team.

Figure 5.3.1 - 6: Capital Expenditure and Investment Portfolio Optimization Process



B.6 Create Capital Investment Register

Alectra Utilities maintains a Capital Investment Register ("CIR") as part of the CopperLeaf C55 system, serving as a clearing house for candidate capital investments with completed business cases. More specifically, the CIR tracks all projects submitted for management review until they are either approved for execution or rejected and removed from the CIR. The CIR captures all relevant project parameters (e.g., new system feeder additions, customers affected, existing feeders impacted, etc.), which enables Alectra Utilities to effectively and accurately evaluate key aspects of capital investment projects, including scheduling and outage coordination.

B.7 Stakeholder Review

Once all the business cases are created in the CIR, Alectra Utilities proceeds with stakeholdering the capital investment needs and solutions. As part of this process, the utility utilizes a Capital Investment Steering Committee comprised of business unit leaders accountable for capital investment implementation. This allows the utility to ensure that the capital investment portfolio adequately addresses all the Corporate Considerations including risk mitigation, rate impact, customer impact, and Corporate Objectives. The stakeholdering process also considers how the investment needs and solutions incorporate the needs, priorities and preferences from customers.

B.8 Optimize 5 Year Investment Portfolio

In order to optimize the investment portfolio, Alectra Utilities utilized the CopperLeaf C55 system to run investment scenarios under multiple constraint conditions. The result of this modeling is known as an "efficiency frontier" which represents the set of optimal investment levels that offer the highest value for a defined level of risk. The efficiency frontier provided the Capital Investment Steering Committee with an important perspective regarding trade-offs among investment expenditure, risk and value. Please refer to Section 5.4.1 for a detailed explanation on the application of the efficiency frontier in the development of the 2020-2024 Capital Investment Plan. On the basis of relevant inputs, the Capital Investment Steering Committee is able to establish the prioritization and pacing of all investments, in alignment with corporate objectives, customer benefits, rate impact, investment needs, and compliance requirements. Please refer to Section 5.4.1 for a detailed explanation of the utility's process for optimizing the 5-Year Capital Investment Portfolio.

B.9 Phase 2 of Customer Engagement – Customer Preferences

The second phase of the customer engagement process focused on projects where Alectra Utilities would be more likely to make changes in response to customer preferences. Specifically, the engagement focused on a subset of projects that offered greater potential for pacing adjustments in response to customer preferences, alongside some exceptional projects that are distinct from the utility's typical capital investment categories. Although all of the projects included in the asset management process are necessary and provide value, Alectra Utilities generally has a greater ability to control the pace of the projects included in the second phase of customer engagement. Please refer to Section 5.2.1.5 Customer Engagement Part D for a detailed explanation of the methodology and outcome of the second phase of customer engagement.

B.10 Finalize Capital Investment Portfolio

Upon the completion of the second round of customer engagement, Alectra Utilities considers and incorporates investment-specific customer preferences, completes further stakeholder reviews through the Capital Investment Steering Committee, and carries out further optimization to establish the final Five-Year Capital Investment Portfolio. Please refer to Section 5.4.1 for a detailed explanation of the portfolio finalization process.

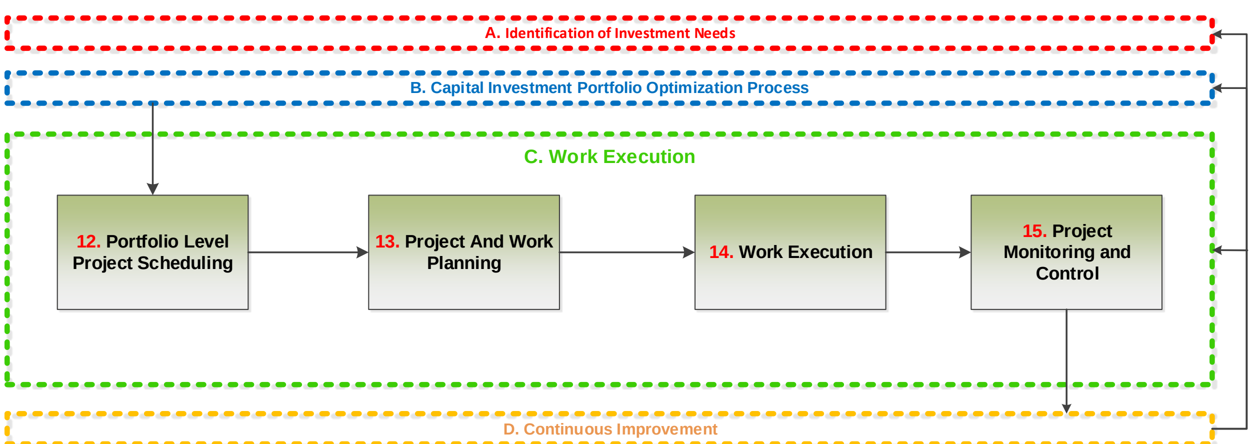
B.11 Incorporate Five-Year Capital Investment Plan into Financial Plan

Following the preceding step, the Capital Investment Steering Committee recommends to Alectra Utilities' Executive Management Team the Five-Year Capital Investment Portfolio which is then incorporated in Alectra Utilities' Five-Year Financial Plan for consideration and approval by Alectra Utilities' Board of Directors. Once the Financial Plan is approved by Alectra Utilities' Board of Directors, the projects and initiatives that make up the Capital Investment Portfolio are presented to Alectra Utilities' Program Delivery Group for work execution.

C Work Execution

Figure 5.3.1 - 7 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 Capital Investment Portfolio are completed according to the approved business cases (including scope and budget).

Figure 5.3.1 - 7: Work Execution



C.12 Portfolio Level Initiatives and Project Scheduling

Alectra Utilities utilizes the Primavera P6 software to ensure a standardized process for planning and monitoring the progress of work execution. More specifically, this Integrated Planning and Scheduling Solution ("iPass") process provides a consolidated view of construction projects and allocation of work across crews. The resulting benefits include enhanced ability to manage construction projects and asset procurement, leading to increased customer satisfaction and productivity improvements.

C.13 Project and Work Planning

By applying the iPass process, Alectra Utilities is able to estimate with reasonable accuracy, based on best information available at the time, the length of time required for design and construction. To minimize the risk of delays to construction starts, detailed designs are completed at a minimum of four months prior to construction, so as to accommodate the processes for obtaining all necessary work permits and scheduling resources and materials.

C.14 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.15 Project Monitoring and Control

The iPass process is an important tool supporting Alectra Utilities in executing all distribution capital and maintenance work on-time and on-budget. The iPass process incorporates continuous project control and monitoring capabilities, as highlighted below:

- Cost Performance Index ("CPI"): measures the utility's ability to complete projects within budget. Actual project costs are measured as a ratio of planned estimated costs. CPI-related variances that exceed 10% are examined for mitigation and improvement.
- Schedule Performance Index ("SPI"): measures the utility's ability to complete projects within a specified duration. SPI is the ratio between the actual versus planned durations of construction, with a target of a maximum 10% variance between the two. Where projects

involve customer connections with an actual target date of completion, both the project duration and expected completion relative to the target and schedule are measured. Alectra Utilities places a high priority on the tracking of SPI for customer connection projects, in support of its commitment to effectively manage and meet customer service obligations, and allowing customers to better plan and manage their internal timelines in relation to expected project completion.

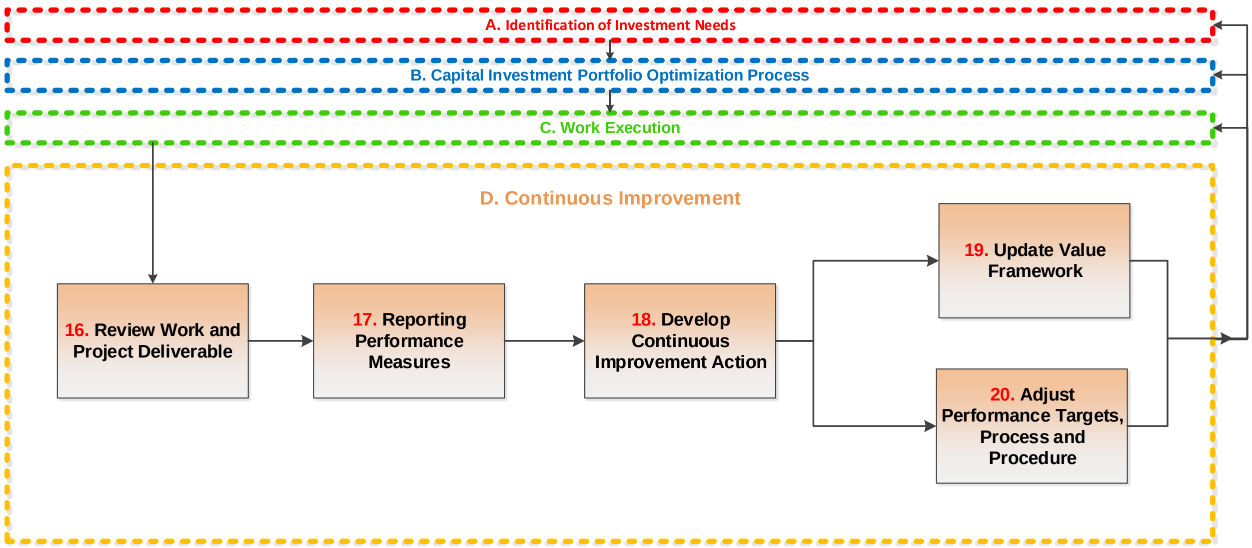
- Request for Change ("RFC"): Change requests (including associated quantity, value, and approval time) are tracked and measured to ensure all changes to work scope, cost and schedule are monitored. Ensuring that work is executed according to plan is crucial to minimizing delays, material stock-outs and cost overruns. Alectra Utilities leverages the information attained from the RFC measure to derive lessons learned to inform and improve future project development, estimation, scheduling and implementation.

D Continuous Improvement

As show in Figure 5.3.1 - 8, Alectra Utilities' continuous improvement process features the following components:

- Review Work and Project Deliverable;
- Reporting Performance Measures (i.e. Key Performance Indicators);
- Develop Continuous Improvement Action;
- Adjust Performance Targets; KPIs, Processes and Procedure; and
- Update Value Framework.

Figure 5.3.1 - 8: Continuous Improvement



D.16 Review Work and Project Deliverable

On a monthly basis, Alectra Utilities monitors year-to-date and projected year-end expenditures, identifying any deviations from plan and takes appropriate corrective actions (including the initiation of a variance review where project spending is expected to materially vary from the approved amount). Where required, projects can be scaled back, cancelled, or otherwise adjusted to reflect the new circumstances and up-to-date information. The utility's senior management reviews program variances on a monthly basis and considers the approval of resource allocation adjustment as may be required.

D.17 Reporting Performance Measures

As noted in relation to the Work Execution step (step 14) of the Asset Management Process, Alectra Utilities' Program Delivery Group monitors and reports on relevant project execution metrics, including CPI, SPI and RFC. Alectra Utilities continuously monitors its capital work implementation and reviews trends, observations and progress through ongoing Production and Scheduling meetings held for each operational zone. The Program Delivery Group coordinates these regular meetings to ensure that lessons learned from all the operational zones within the utility's service area are effectively communicated and addressed in a timely manner.

D.18 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. Examples of events that may trigger continuous improvement actions include:

- Organizational changes;
- Mergers and acquisitions involving other local distribution companies;
- Major municipal, regional or provincial projects;
- Economic downturn (local or widespread);
- Changing regulatory requirements;
- Force majeure and emergency events (e.g., tornado, ice storms, wind storms, flooding, fire); and
- Not meeting established goals and targets.

Where warranted, the need for improvements and underlying lessons will form part of the considerations for purposes of affirming or refining the utility's corporate vision, mission, values, and asset management process (including the approach for selecting and prioritizing investments).

D.19 Update Value Framework

The final step in the Continuous Improvement phase of the Asset Management Process incorporates the learning from capital planning, corporate objectives and risks (listed in Table 5.3.1 - 7), customer preferences, work execution and project monitoring and control to assess the Value Framework described in Part A – Capital Planning Process of this section. The goal of this assessment is to calibrate the Value Measures to be used in the next Asset Management Process cycle. In this step, Alectra Utilities' Asset Management group gathers feedback from stakeholders and project leads on the questionnaire used for scoring projects and determines if adjustments and calibration are required to appropriately capture all relevant and up-to-date investment values and measures. Alectra Utilities makes any required adjustments to the Value Framework in the CopperLeaf C55 system, provides related training to all system users, and incorporates these changes into the Asset Management Process cycle going forward. Please refer to Section 5.4.1 for a detailed explanation of the Value Framework.

D.20 Adjust Performance Targets, Processes and Procedures

In order to ensure continuous improvement, Alectra Utilities tracks and monitors a number of performance measures in relation to the Work Execution and Capital Planning phases of its Asset Management Process with a focus on customer-oriented performance, cost efficiency and effectiveness, and asset and/or system performance improvement. Alectra Utilities completes an annual review of the performance measures to ensure the established targets are achieved in an effective and consistent manner. Where appropriate, the utility identifies and adopts adjustments to performance targets and/or improvements to relevant processes and procedures to foster continuous improvement.

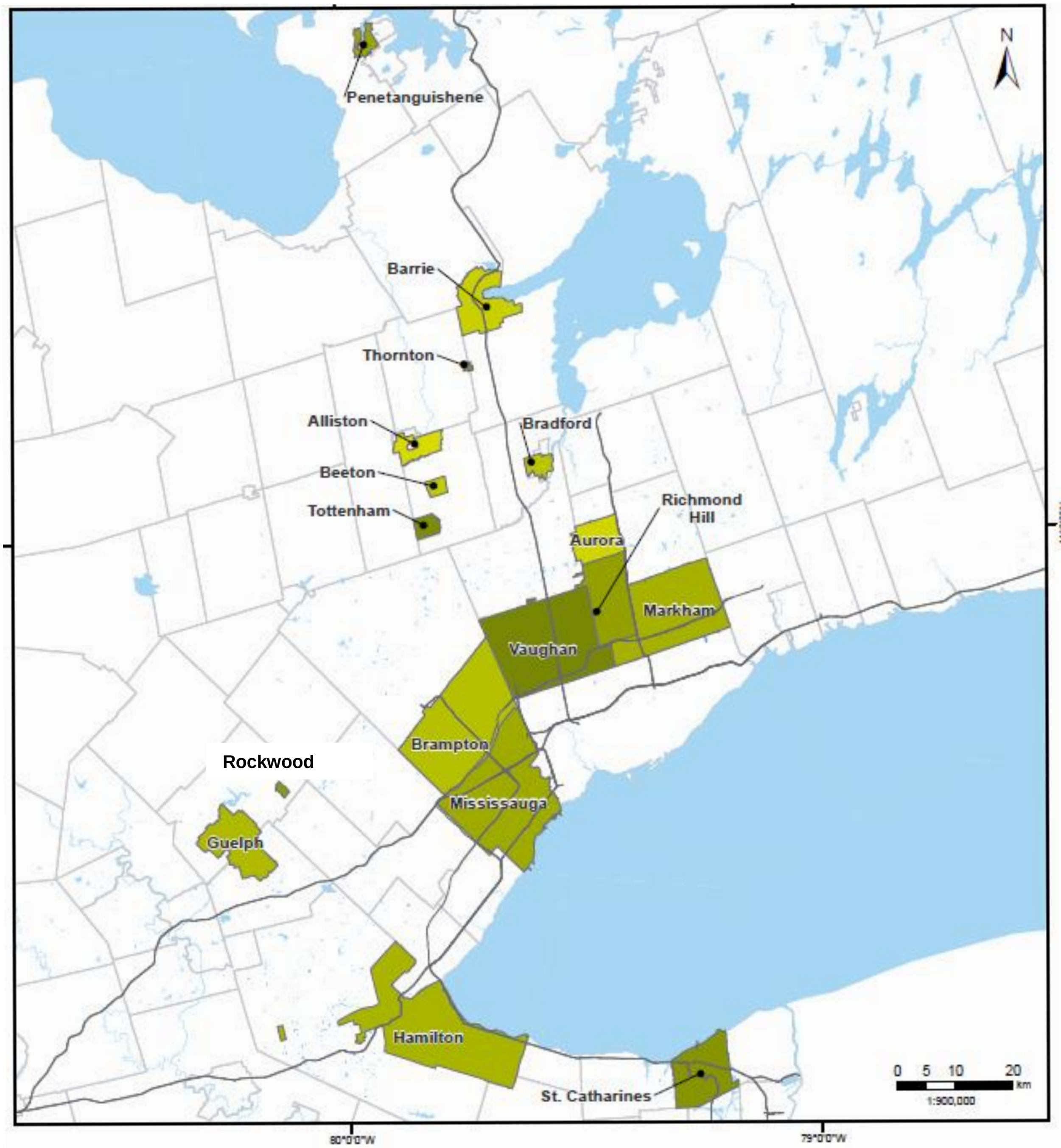
5.3.2 OVERVIEW OF ASSETS MANAGED

5.3.2.1 SERVICE AREA AND CUSTOMERS

Alectra Utilities was formed by the merger of the three Greater Toronto and Hamilton Area (GTHA) utilities, and the purchase of Hydro One Brampton, on March 1 2017. Following the formation of Alectra Utilities, Guelph Hydro merged with Alectra Utilities on Jan 1, 2019. Alectra Utilities is the largest municipal electrical utility in Canada. It 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. The service territory spans 1,827 sq. km, and Alectra Utilities provides electricity to over one million customers in that area.

Figure 5.3.2 - 1 shows Alectra Utilities' geographic service area:

Figure 5.3.2 - 1: Alectra Utilities' Service Area



Alectra Utilities' service area has been organized into four operating areas. These operating areas comprise the following communities:

1) East – York Region (Vaughan, Markham, Richmond Hill and Aurora) and Simcoe County (Barrie, Bradford, Beeton, Tottenham, Alliston, Thornton and Penetanguishene)
2) Central – Peel Region (Mississauga and Brampton)
3) West – Hamilton and St. Catharine's
4) SouthWest – Guelph and the Village of Rockwood.

Alectra Utilities serves over 1 million customers with a non-coincident peak load of 5,517MW (including Guelph) as of 2018.. Table 5.3.2 - 1 shows the customer counts and loads as of Dec 31, 2018. The majority of the customer count is residential (90%), however, they represent only about 29% of the load.

Table 5.3.2 - 1: Customer Account and Consumption

Rate Class	Customer Count	Consumption (kWh)
Residential	949,231	7,318,383,988
General Service Less Than 50 kW	83,718	2,660,361,304
General Service >= 50 kW	13,794	12,612,289,044
Large User	32	2,685,576,529
Embedded Distributor(s)	1	3,402,773
Street Lighting Connections	228,924	115,948,218
Sentinel Lighting Connections	545	768,702
Unmetered Scattered Load Connections	11,277	42,555,586
TOTAL	**1,287,522**	**25,439,286,145**

5.3.2.2 POPULATION TRENDS

Steady population growth is expected in Alectra Utilities' service area for the next twenty years. Table 5.3.2 - 2 illustrates the forecasted population growth across major municipalities and regions in Alectra Utilities' service area for the period from 2016 to 2041.

Table 5.3.2 - 2: Population and Household Growth Forecast – 2016-2041

Year	Measure	Brampton	Mississauga	Hamilton	York	Guelph	Simcoe County	St. Catharines
2016	Population	593,638	721,599	536,917	1,109,909	131,794	479,650	133,113
	Households	168,010	240,910	216,325*	366,160*	52,090	173,310	57,020
2021	Population	683,700	777,730	599,400	1,245,900	148,000	499,000	136,930
	Households	189,520	252,230	228,850	408,880	59,200	194,300	58,330
2026	Population	755,710	808,260	634,300	1,349,200	158,000	537,000	142,560
	Households	210,860	265,660	245,645*	451,625*	63,200	216,030	59,720
2031	Population	811,970	842,070	669,900	1,457,400	169,000	575,000	150,590
	Households	227,610	279,140	262,450	494,380	67,600	236,760	61,120
2041	Population	890,000	920,020	740,700	1,683,600	191,000	659,000	167,480
	Households	250,460	307,470	298,400	559,160	76,400	281,500	
% Increase Population		49.92%	27.50%	37.95%	51.69%	44.92%	37.39%	25.82%
% Increase Households		49.07%	27.63%	37.94%	52.71%	46.67%	62.43%	7.19%**

Notes:	
*	This data is estimated by linear interpolation using available data
**	This percentage is based on households in 2031
1.	**All Population data for 2016 comes from:** "Census Profile, 2016 Census", Statistics Canada. URL: https://www12.statcan.gc.ca/census-recensement/2016/dp-pd/prof/index.cfm?Lang=E
2.	**Brampton and Mississauga Population (2021-2041) and Housing (2016-2041) Data:** "Region of Peel Housing Strategy", SHS Consulting, July 2018, URL: https://www.peelregion.ca/planning/officialplan/pdfs/2018/2018-housing-strategy.pdf
3.	**Hamilton and York Population (2021-2041) Data:** "Ontario Population Projections Update, 2017-2041", Ontario Ministry of Finance, 2018, URL: https://www.fin.gov.on.ca/en/economy/demographics/projections/

4.	**Hamilton and York Housing (2016-2041) Data:** “Greater Golden Horseshoe Growth Forecasts to 2041”, Hemson Consulting Ltd., June 2013, URL: https://www.hemson.com/wp-content/uploads/2016/03/HEMSON-Greater-Golden-Horseshoe-Growth-Forecasts-to-2041-Technical-Report-Addendum-and-Rev.-Appendix-B-Jun2013.pdf
5.	**Guelph Population (2031) Data:** https://guelph.ca/business/economic-development-office/guelph-quicksheet/ 2031 Projected Population = 169,000
6.	**Guelph Population (2041) Data:** http://placestogrow.ca/index.php?option=com_content&task=view&id=430&Itemid=14 2041 Projected Population = 191,000
7.	**Guelph Housing (2016) Data:** https://www12.statcan.gc.ca/census-recensement/2016/dp-pd/prof/details/page.cfm?Lang=E&Geo1=CSD&Code1=3523008&Geo2=CD&Code2=3523&Data=Count&SearchText=Guelph&SearchType=Begins&SearchPR=01&B1=All&TABID=1 2016 Number of Households = 52,090
8.	**Guelph Population (2021-2041) and estimated Housing (2021-2041) Data:** http://guelph.ca/wp-content/uploads/ 2012CommunityProfile.pdf Avg. No. of people per household = 2.5 is used to calculate the future projections based on this report.
9.	**St. Catharines Population (2021-2041) Data:** “How We Grow – Niagara 2041”, Niagara Region, URL: https://www.niagararegion.ca/2041/pdf/mcr-pic3-boards.pdf
10.	**St. Catharines Housing (2016-2031) Data:** “Table 4-1: Niagara Region, Population, Household and Employment Forecast by Local Minicipality, 2006 – 2031”, Niagara Region, URL: https://www.niagararegion.ca/living/icp/pdf/2015/Table-4-1.pdf
11.	**Simcoe County Population (2021-2041) and Housing (2016-2041) Data:** “Greater Golden Horseshoe Growth Forecasts to 2041”, Hemson Consulting Ltd, Nov. 2012, URL: https://hemson.com/wp-content/uploads/2016/03/HEMSON-Greater-Golden-Horseshoe-Growth-Forecasts-to-2041-Technical-Report-Nov2012.pdf
12.	York Region- Numbers indicated are for the entire York Region. Alectra Utilities service territory includes Markham, Vaughan, Richmond Hill and Aurora.
13.	Simcoe County –Numbers indicated are for the entire Simcoe County region. Alectra Utilities service territory includes Barrie, Bradford, Thornton, Alliston, Beeton, Tottenham and Penetanguishene.

Projections indicate that there will be significant increases in population and the number of households in Brampton, the York Region and Guelph, as well as growth caused by intensification and redevelopment in Mississauga and Hamilton.

Projections outlined in Table 5.3.2 - 2 indicate that an average population growth of 39.3%, and an average growth of 40% in the number of households, is anticipated by 2041. Although Alectra Utilities' planned investments are based on localized growth projections in specific areas, this overall trend suggests that Alectra Utilities will need to continue investing in expansion projects to keep pace with the increasing growth in its service territory for decades.

The sustained growth in population and the number of households is expected to increase demand for electricity. This increase will require Alectra Utilities to invest in stations and line capacity projects, as well as new customer connections. Municipalities and transit authorities also continue to build new roads and widen existing roads. This will require Alectra Utilities to continue to invest in the installation and relocation of assets. New transit projects, such as the Mississauga and Hamilton LRTs, and the GO electrification, will require Alectra Utilities to continue to invest in transmission infrastructure to meet the growth in demand that this is expected to cause.

A Load Forecast (2019-2028)

Alectra Utilities' service territory is not electrically connected. It is spread out over a vast geographic area, with each operating area peaking on different days of the year. Therefore, for capacity planning purposes, each area is analyzed, separately.

Figure 5.3.2 - 2 shows the historic non-coincident peak. The maximum non-coincident peak recorded was 5,839 MW in 2014.

Alectra Utilities is a summer peaking utility and has a high correlation with the summer temperatures. The non-coincident peak in 2018 increased by 6.47% as compared to 2017.

The summer of 2017 was cooler than normal. There were only 4 days when the weighted 3-day average temperature was over 30°C in the summer. It was the eighteenth coldest summer in the last 40 year period.

The summer of 2018 was hotter than normal. There were a total of 14 days when the weighted 3-day average temperature was over 30°C in the summer. It was the fifth hottest summer in the last 40 year period.

Figure 5.3.2 - 2: Historic Non Coincident Peak

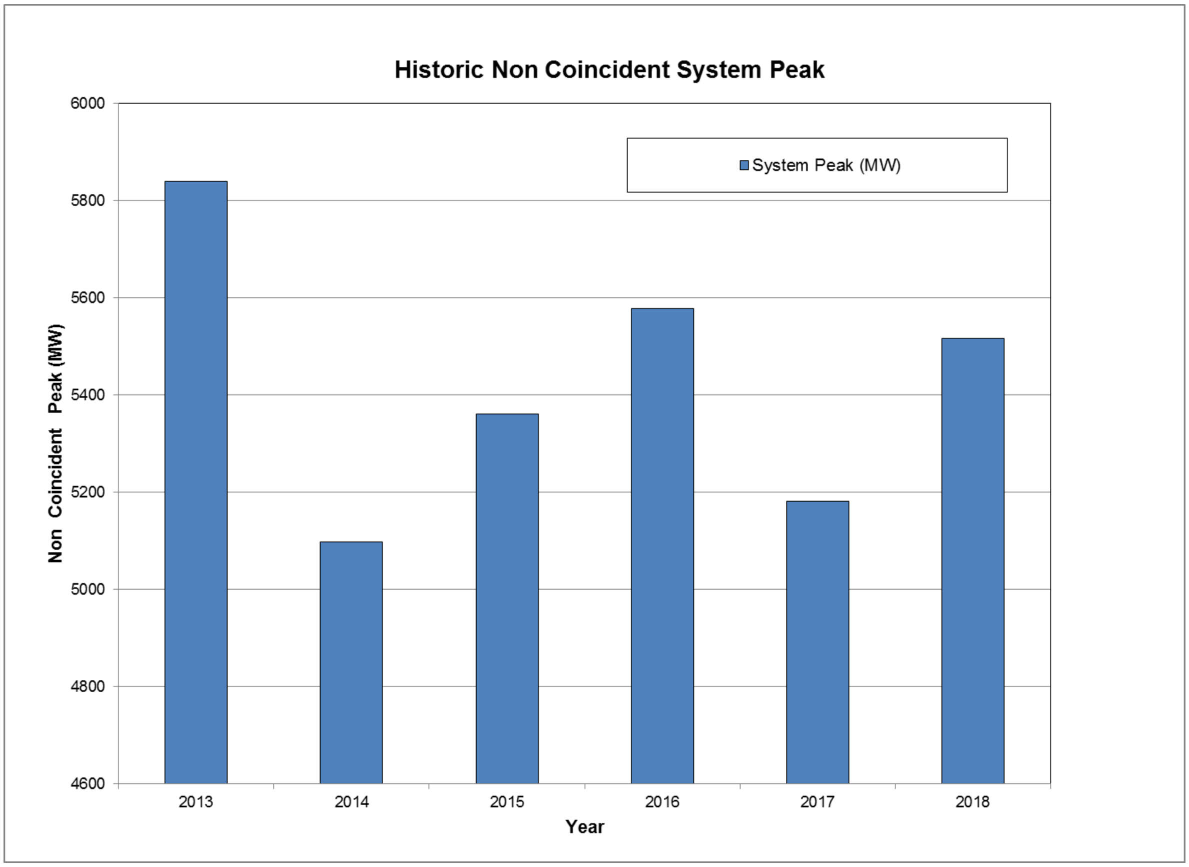
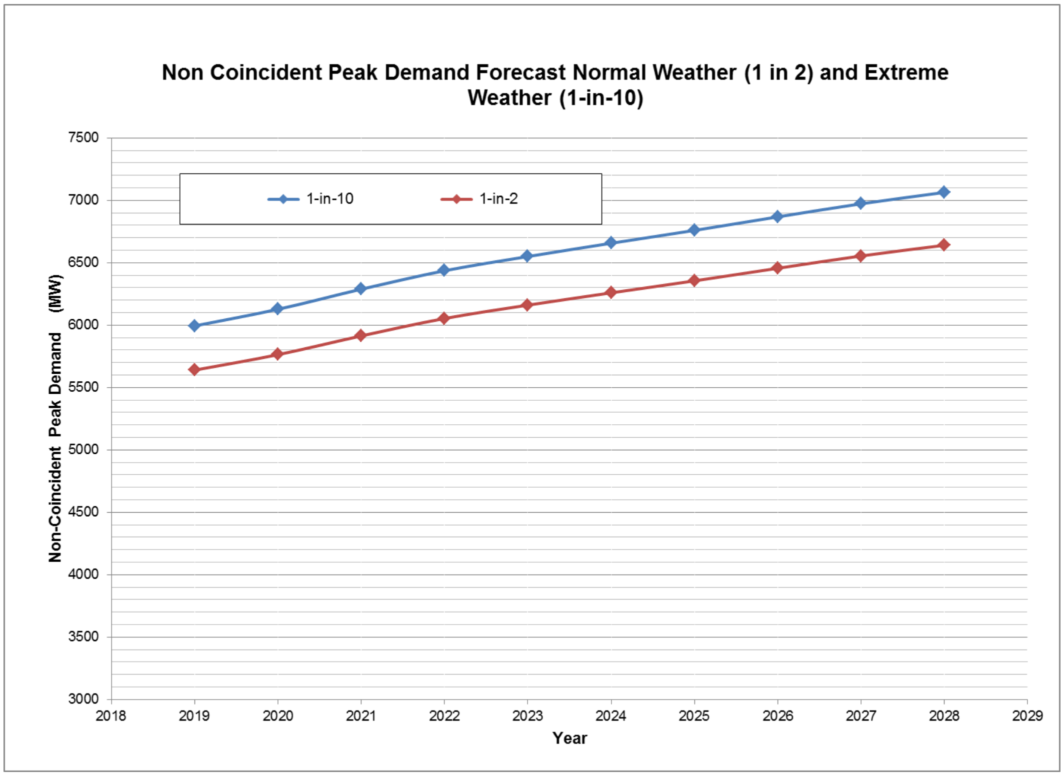


Figure 5.3.2 - 3 shows the projected non coincident peak demand from 2019 to 2028 under the normal (1 in 2) and extreme weather (1 in 10) scenario. Alectra Utilities completes an annual load forecast and system adequacy assessment based on the load forecast process. The load forecast process can be found in DSP Section 5.3.1 – A.1.3.2 – Load Forecast and System Adequacy Assessment.

Figure 5.3.2 - 3: Non Coincident Peak Demand Forecast 2019-2028



Alectra Utilities plans to expand and upgrade existing station and distribution systems to support new connections to ensure that safe and reliable service is maintained for existing customers.

Investments to support the expansion of the distribution system and new connections are detailed in Appendix A – Investment Summaries

- Appendix A02 - Customer Connections
- Appendix A12 – Lines Capacity
- Appendix A13 – Stations Capacity

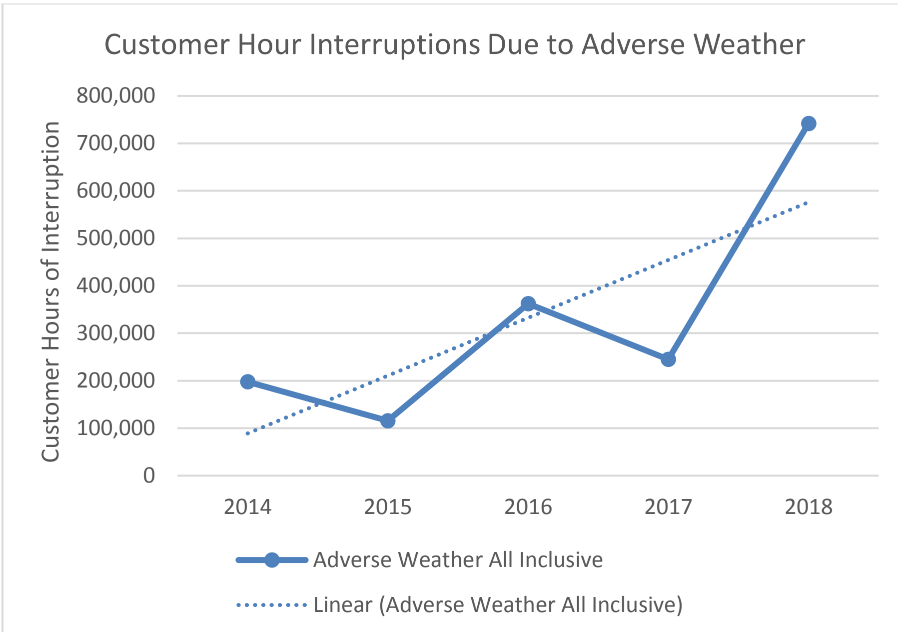
5.3.2.3 CLIMATE TRENDS

Alectra Utilities monitors and assesses climate impacts to ensure that distribution system investments continue to operate in a safe and reliable manner in light of climate and environmental trends.

Since 2014, adverse weather has been one of the top four contributors to system average interruption duration index ("SAIDI") and system average interruption frequency index ("SAIFI").

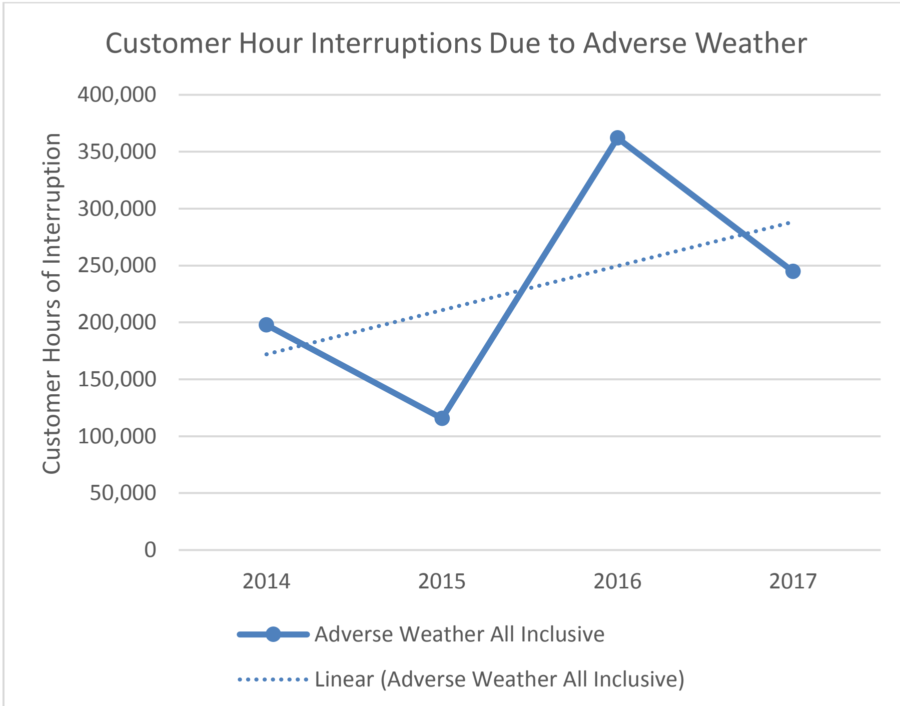
Figure 5.3.2 - 4 illustrates the increasing number of outage events caused by adverse weather at Alectra Utilities.

Figure 5.3.2 - 4: Customer Hours of Interruption Due to Adverse Weather Outages (2014-2018)



From 2014 to 2018, Alectra Utilities experienced an 86% increase in customer hours of interruption from adverse weather conditions. Alectra Utilities has determined that duration of outage events from adverse weather is directly correlated to system endurance and resilience. Alectra Utilities' assessment of outage events caused by adverse weather indicates that segments of the distribution system that are in poor or very poor condition are more susceptible to failure as a result of adverse weather. Even if you remove 2018 as seen in Figure 5.3.2 - 5 illustrates the increasing trend in Customer Hours of Interruption ("CHI") due to adverse weather.

Figure 5.3.2 - 5: Customer Hours of Interruption Due to Adverse Weather Outages (2014-2017)



In order to address this issue, Alectra Utilities has developed plans to mitigate the impacts of storms. These plans include the renewal of the distributions system using present day standards, investments in storm hardening initiatives, and the renewal of overhead distribution systems in areas susceptible to adverse weather conditions. For example, investment in eliminating four circuit poles are part of Alectra Utilities' adverse weather mitigation efforts.

For a detailed analysis of weather impacts over a 30 year period for Alectra Utilities' service territory, please see Appendix N – Climate and Trend.

5.3.2.4 SUMMARY OF SYSTEM CONFIGURATION

Alectra Utilities' distribution system consists of stations, infrastructure, and distribution infrastructure, which includes overhead and underground lines. The station infrastructure consists of 14 Alectra Utilities Owned Transformer Stations (TS), and 65 HONI owned TSs which are connected to the 230/115 kV provincial transmission grid. Alectra Utilities owns and operates 155 Municipal Transformer (MS) stations that further step down voltage to 13.8kV, 8.32kV or 4.16kV. The distribution infrastructure consists of a total of 1,406 feeders, 99 at 44kV, 290 at 27.6kV, 701 at 13.8kV, 16 at 8.32kV and 300 at 4.16kV. As of December 2018, Alectra Utilities' total overhead circuit length is 5,406 km, and its total underground circuit length is 11,514 km.

Alectra Utilities' service area has been divided into four operating areas. The operating areas are further subdivided for planning purposes.

The four operating areas and the subdivided parts for planning are:

- East (2 planning parts – York Region and Simcoe County)
- Central (2 planning parts – Brampton and Mississauga)
- West (2 planning parts Hamilton and St. Catharines)
- Southwest (2 planning parts – Guelph and Rockwood)

A Alectra Utilities East

A.1 York Region

Alectra Utilities' East service territory is divided into two distinct geographic regions: north and south. As depicted in Figure 5.3.2 - 6, the south consists of Vaughan, Markham, Richmond Hill and Aurora (York Region). York Region supplies Vaughan, Richmond Hill and Markham, mainly through a 27.6 kV network.

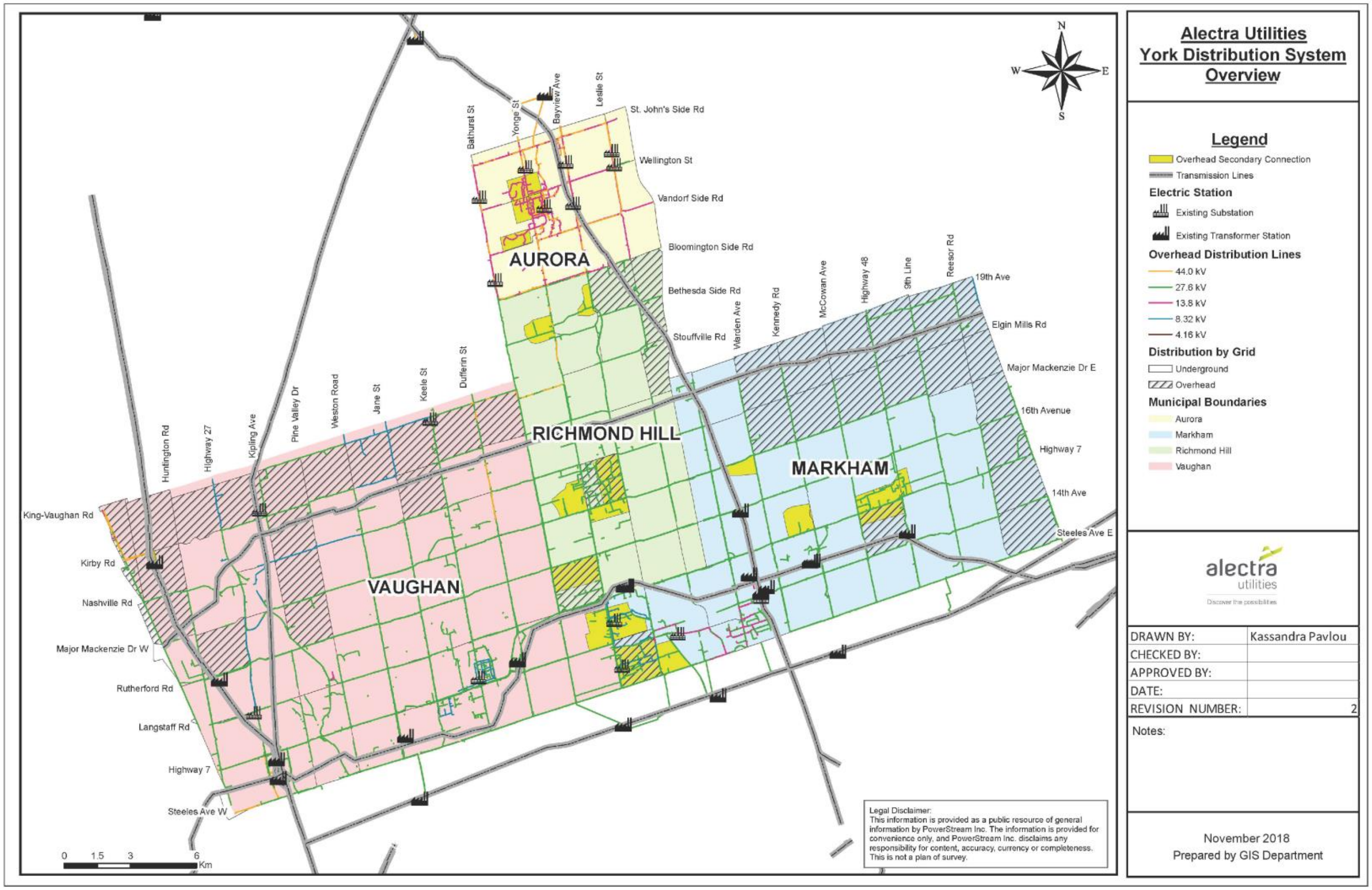
There are three distribution voltages in York Region's network: 27.6 kV, 13.8 kV and 8.32 kV. For the most part, York Region is supplied from 27.6 kV voltage level to distribute electricity throughout Markham, Richmond Hill and Vaughan. A small amount of load (approx.1.0%) is supplied at 8.32kV or 13.8 kV from Municipal Substations (MS), including Aurora.

The 13.8kV and 8.32kV systems are fed from substations in Vaughan and Markham in the form of isolated islands. As of October 2018, there are two 27.6kV/13.8kV substations and two

27.6/8.32kV substations in Markham. There is one 27.6/8.32 kV substation in Vaughan. There are no 13.8kV or 8.32kV systems in Richmond Hill. Aurora is supplied by five 44kV feeders originating from Armitage TS in Newmarket and eight stations at 44/13.8kV.

Figure 5.3.2 - 6 depicts the Alectra Utilities' (south York Region) distribution system.

Figure 5.3.2 - 6: York Region Distribution System Overview



A.1.1 York Region Municipal Substations

Figure 5.3.2 - 7 to Figure 5.3.2 - 9 provide the location of Alectra Utilities' municipal sub-stations for the York Region territory.

Figure 5.3.2 - 7: Aurora Substation Locations

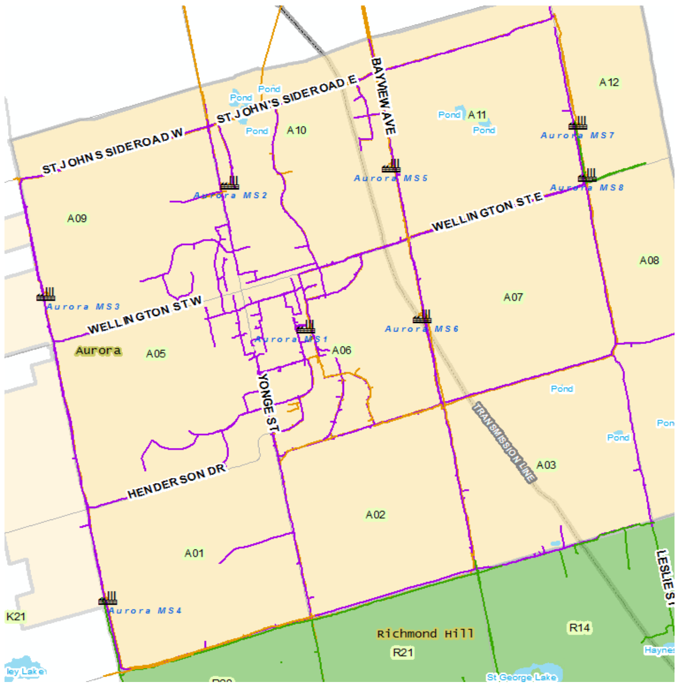


Figure 5.3.2 - 8: Vaughan Substation Locations

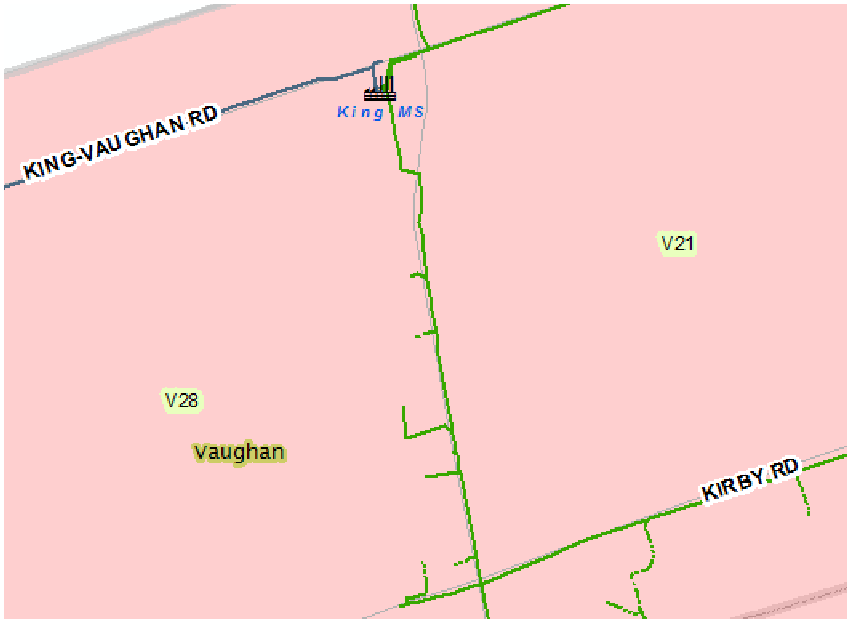
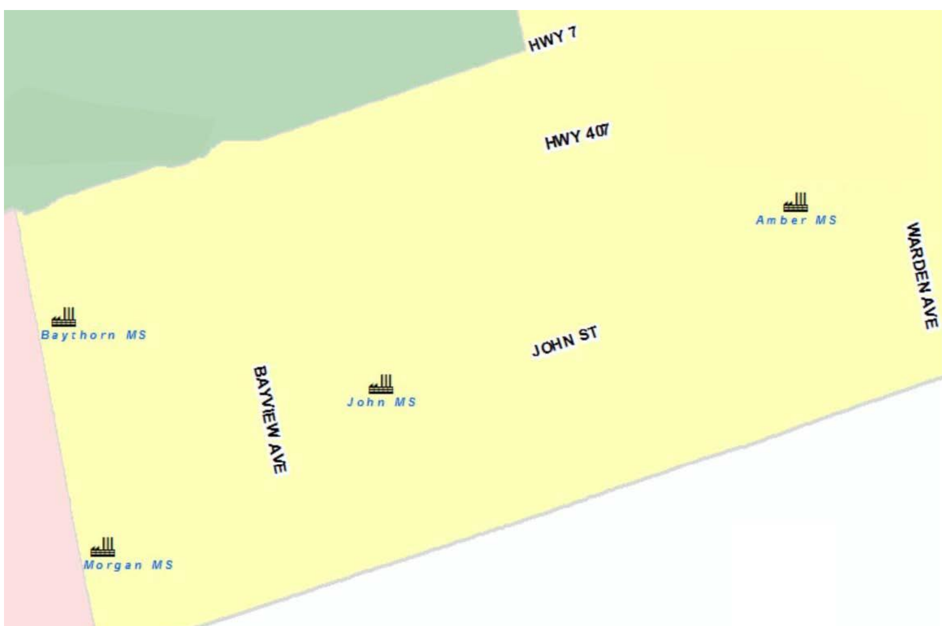


Figure 5.3.2 - 9: Markham Substation Locations



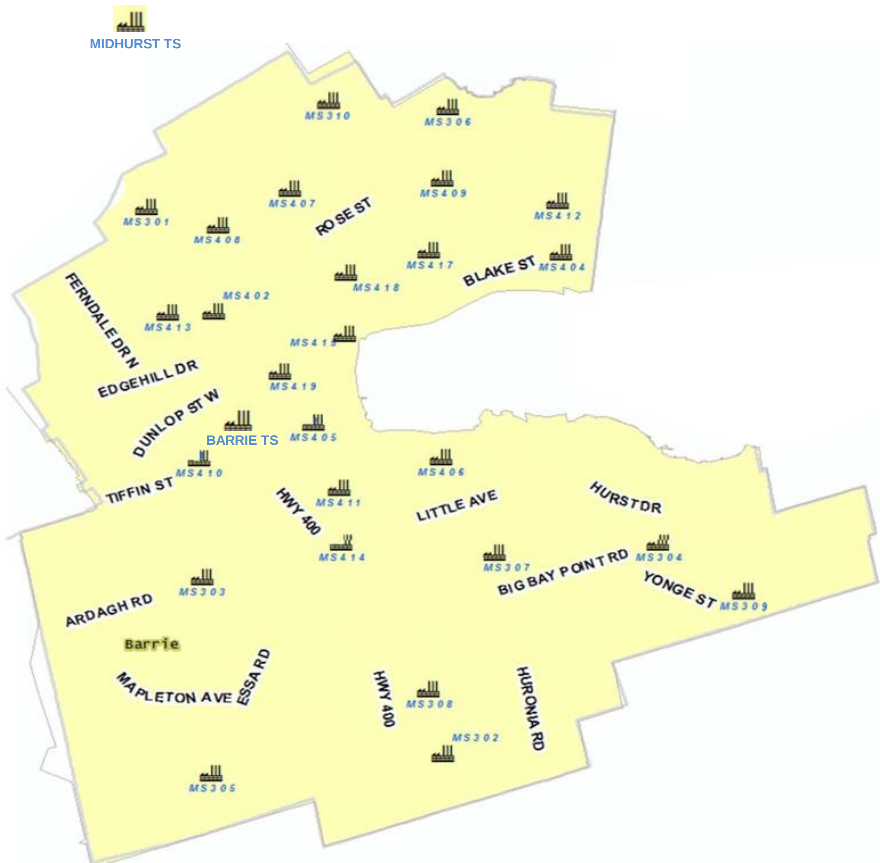
A.2 Simcoe County

Alectra Utilities East Simcoe County is divided into five regions: Barrie, Bradford, New Tecumseth (Alliston, Beeton, and Tottenham), Penetanguishene and Thornton.

A.2.1 Barrie

Barrie is supplied by three Hydro One owned and operated transformer stations: Barrie TS, Midhurst T1/T2 and Midhurst T3/T4. Each transformer station consists of two transformers operating in parallel. Barrie is currently supplied by fourteen 44kV feeders from the Hydro One transformer stations: five from Barrie TS (13M7 to be in-service 2019), four from Midhurst T1/T2, and five from Midhurst T3/T4 (23M22 and 23M27 to be in-service 2019). These 44kV feeders service municipal substations ("MS") and multiple customer-owned substations. The municipal substations transform the 44kV sub-transmission voltage to distribution voltages of 4.16kV and 13.8kV. There are twenty-five municipal substations in Barrie; ten 13.8kV MS's and sixteen 4.16kV MS's. Figure 5.3.2 - 10 shows the Barrie substation locations.

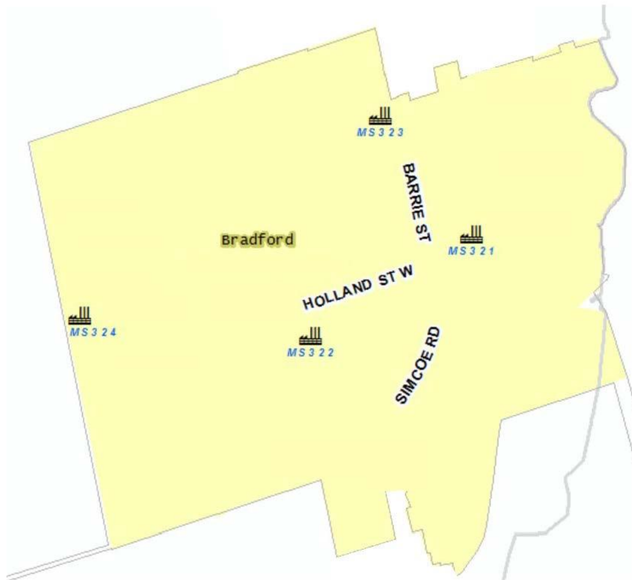
Figure 5.3.2 - 10: Barrie Substation Locations



A.2.2 Bradford

Bradford is supplied by a Hydro One owned and operated transformer station, Holland TS. Bradford is currently supplied by three 44kV feeders from Holland TS: 153M3, 153M4, and 153M10. These feeders also supply some Hydro One load outside of Alectra Utilities' service territory. These 44kV feeders service municipal substations and multiple customer-owned substations. The municipal substations transform the 44kV sub-transmission voltage to a distribution voltage of 13.8kV. There are four municipal substations in Bradford: MS321, MS322, MS323, and MS324. Refer to Figure 5.3.2 - 11.

Figure 5.3.2 - 11: Bradford Substation Locations



A.2.3 New Tecumseth

New Tecumseth consists of three separate supply regions; Alliston, Beeton and Tottenham. For distribution purposes, these three areas are considered separately because the distances between them are too large for distribution feeders to be interconnected. All three areas are supplied by one Hydro One 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 Hydro One to supply Alliston loads. The 138M8 is dedicated to Alectra Utilities to supply load in Beeton and Tottenham. These 44kV feeders service municipal substations and multiple customer-owned substations. The municipal substations transform the 44kV sub-transmission voltage to distribution voltages of 4.16kV, 8.32kV, and 13.8kV. There are five municipal substations in Alliston; three 13.8kV MS's and two 4.16kV MS's. There is a single 13.8kV municipal substation in Beeton with two transformers on site. There are two 8.32kV municipal substations in Tottenham. Refer to Figure 5.3.2 - 12 to Figure 5.3.2 - 14 for the substation location.

Figure 5.3.2 - 12: Alliston Substation Locations

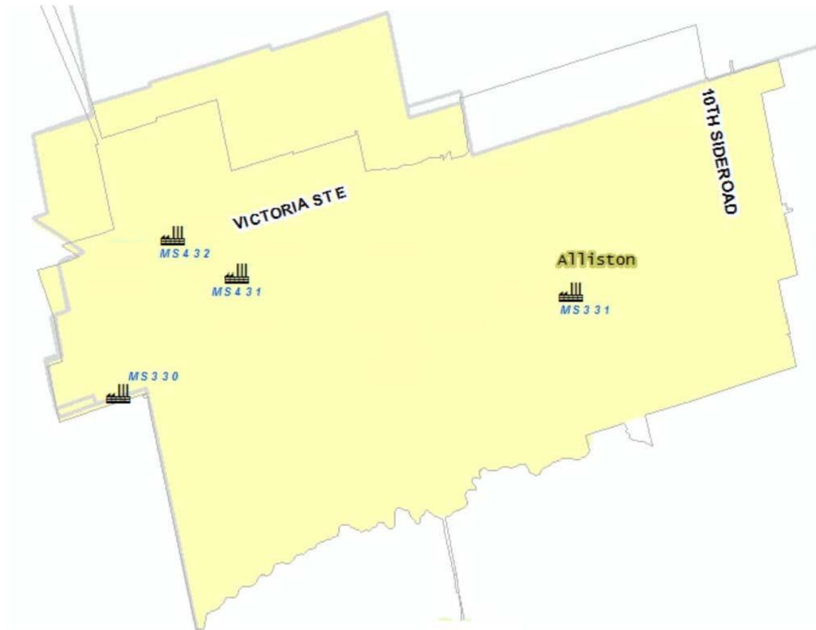
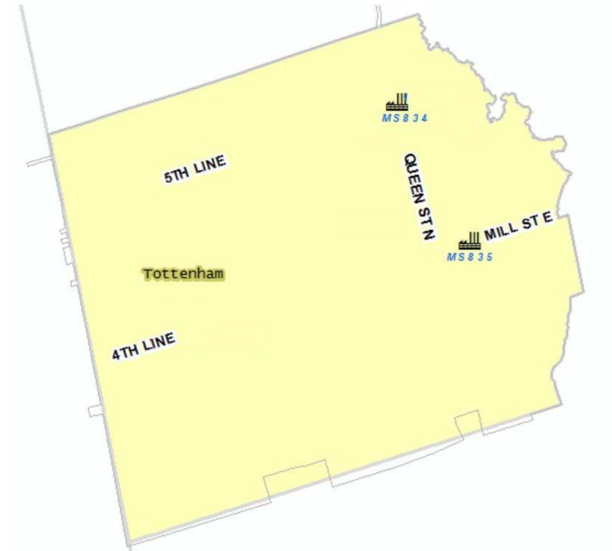


Figure 5.3.2 - 13: Beeton Substation Locations

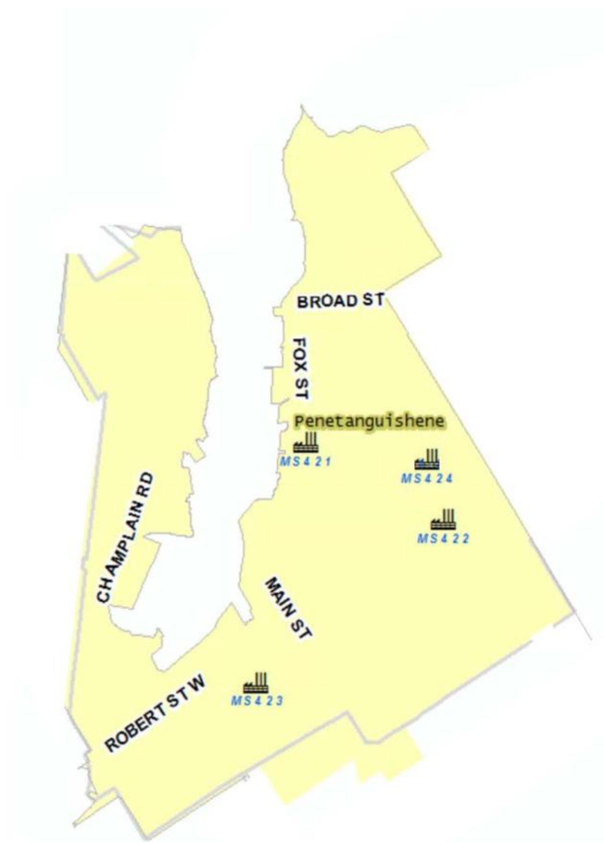
Figure 5.3.2 - 14: Tottenham Substation Locations



A.2.4 Penetanguishene

Penetanguishene is supplied from one Hydro One owned and operated transformer station, Waubaushene TS. Penetanguishene is currently supplied by two 44kV feeders from Waubaushene TS: 98M3 and 98M7. These feeders also supply some Hydro One load outside of Alectra Utilities' service territory. These 44kV feeders service municipal substations and multiple customer-owned substations. The municipal substations transform the 44kV sub-transmission voltage to a distribution voltage of 4.16kV. There are four municipal substations in Penetanguishene: MS421, MS422, MS423, and MS424. There is also a Hydro One owned 8.32 kV substation in Penetanguishene that supplies Alectra Utilities' load along Champlain Road with a single 8.32kV feeder. Refer to Figure 5.3.2 - 15 for the substation location.

Figure 5.3.2 - 15: Penetanguishene Substation Locations



A.2.5 Thornton

Thornton is supplied by one 8.32 kV feeder that is shared with Hydro One out of the Hydro One owned and operated Thornton DS.

B Alectra Utilities Central

Alectra Utilities Central is divided into two regions: Brampton and Mississauga.

B.1 Brampton

The supply for Brampton is sourced from four Hydro One owned and operated 230kV transformer stations: Goreway TS, Bramalea TS, Pleasant TS and Woodbridge TS, with secondary voltages of 44kV and 27.6kV. Alectra Utilities owns and operates one 230kV transformer station constructed in 2001 with a secondary voltage of 27.6kV (Jim Yarrow MTS).

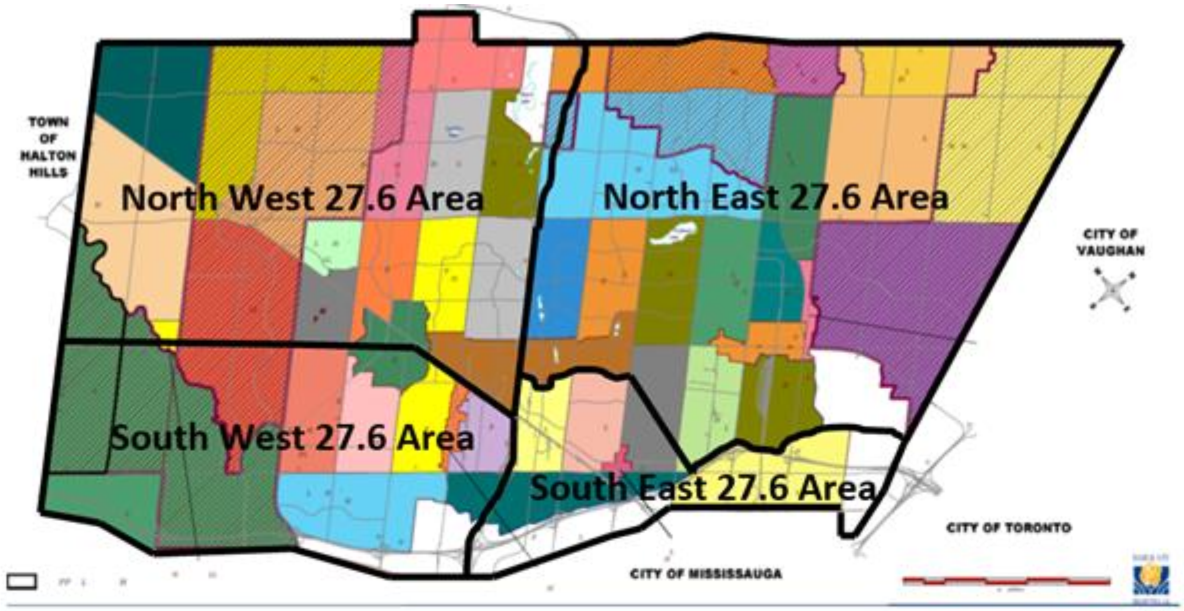
Alectra Utilities connects the secondary of the transformer stations to its distribution system using 61 feeder breakers in total. Further step-down from the 44kV and 27.6kV sub-transmission voltages is performed at 9 municipal substations to primary distribution voltages of 13.8V, 8.32 kV and 4.16kV, which are connected to the distribution system using 40 feeders.

The 27.6kV feeders supplying Brampton are divided into North, South, East, and West Sections:

- North West Zone bounded by Mayfield Road to the north, Highway 410 to the east, CN Railway/Queen Street/Embleton Road to the south, and Winston Churchill Boulevard to the west.
- South West Zone bounded by CN Railway/Queen Street/Embleton Road to the north, Highway 410 to the east, Brampton City limits to the south, and Winston Churchill Boulevard to the west.
- North East Zone bounded by Mayfield Road to the north (City limits), Highway 50 to the east, Highway 407 / Clark Boulevard to the south, and Highway 410 to the west.
- South East Zone bounded by Highway 407 / Clark Boulevard to the north, Highway 50 to the east, Brampton city limits to the south, and Highway 410 to the west.

Refer to Figure 5.3.2 - 16 and Figure 5.3.2 - 17 for planning sections and Figure 5.3.2 - 18 for the substation locations.

Figure 5.3.2 - 16: Brampton Planning sections

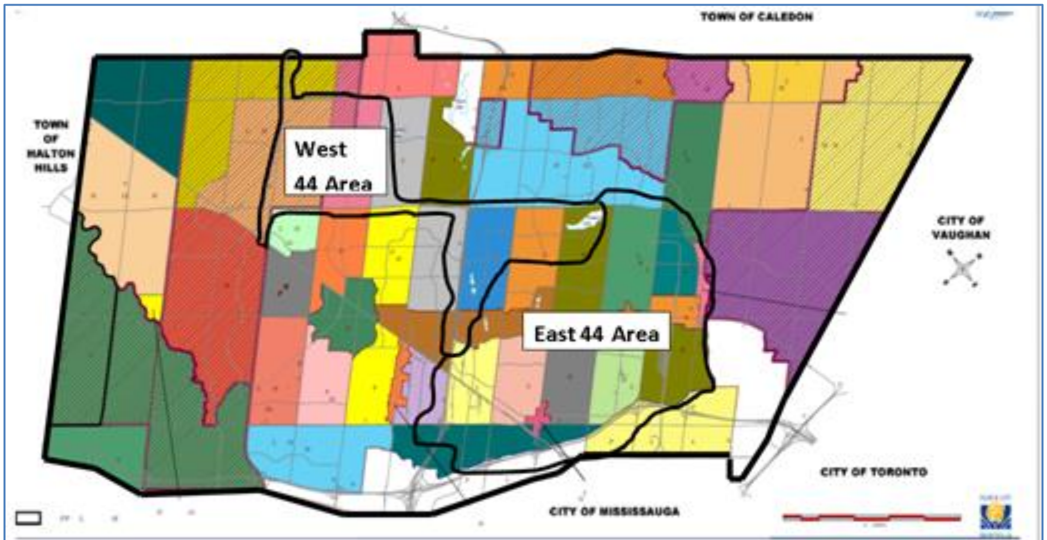


Note: 1) North West 27.6 Area supplied from Pleasant TS
2) South West 27.6 Area Supplied from Jim Yarrow TS
3) North East 27.6 Area Supplied from Goreway TS
4) South East 27.6 Area Supplied from Bramalea TS

The 44kV feeders supplying Brampton are divided into east and west Sections.

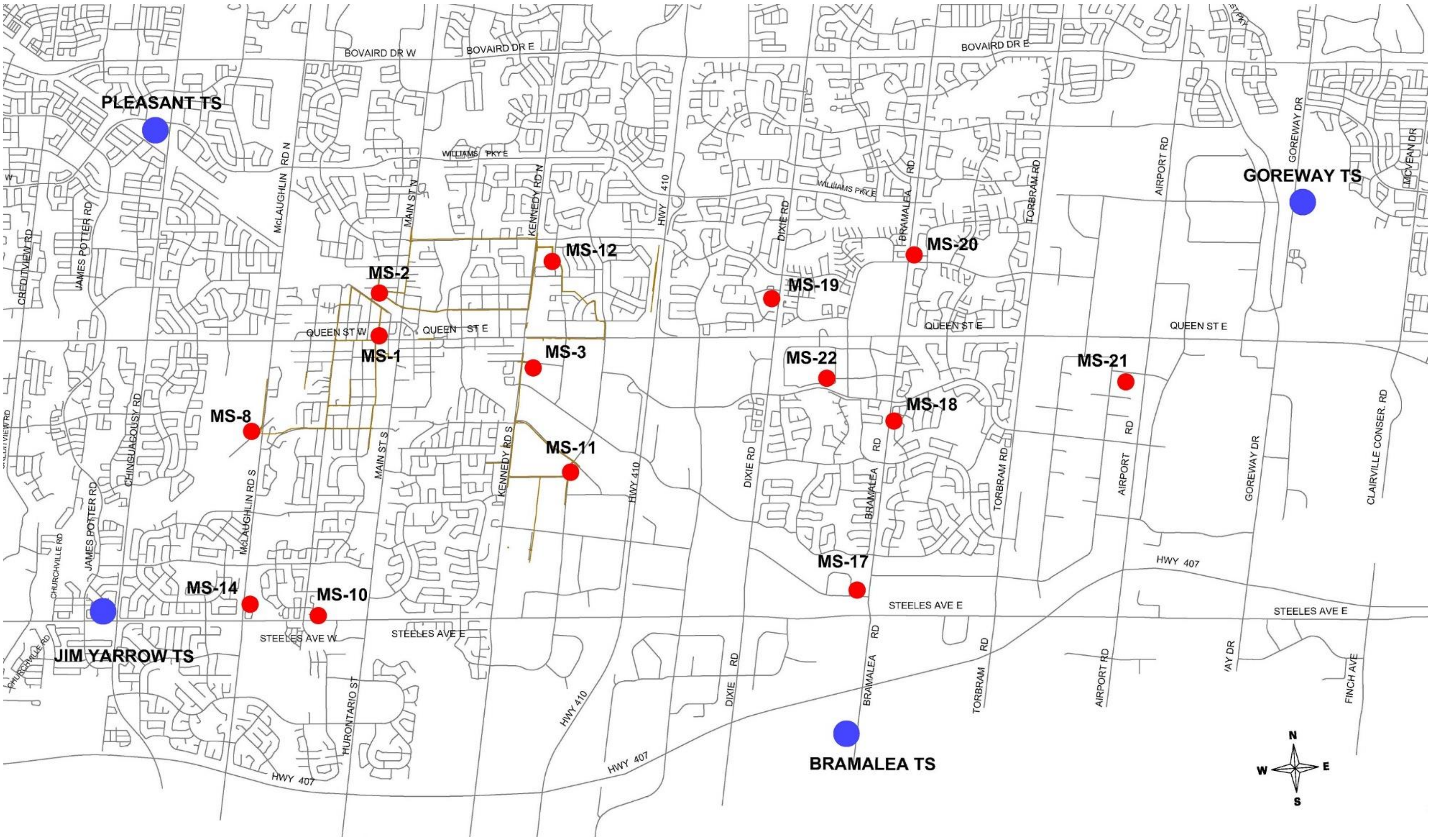
- West 44kV Area: This area covers of a small pocket of 44kV load in the Van Kirk Drive area from Bovaird Drive to Sandalwood Parkway. The area is supplied by 44kV buses from the Pleasant TS. The remaining West 44kV system load is located in the Dixie Road to Bramalea Road area from Queen Street to Bovaird Drive.
- East 44kV Area: This older industrial area extends from Heart Lake Road to Airport Road, and from Steeles Avenue to Bovaird Drive. The area is supplied by 44kV buses from the Goreway TS, Bramalea TS, and Woodbridge TS. The 44kV load area combines smaller residential and commercial with larger industrial zoning.

Figure 5.3.2 - 17: Brampton Planning sections



Note: 1) West 44 Area supplied supplied from Pleasant TS
2) East 44 Area Supplied from Bramalea TS, Goreway TS and Woodbridge D6M16

1 **Figure 5.3.2 - 18: Brampton Stations**



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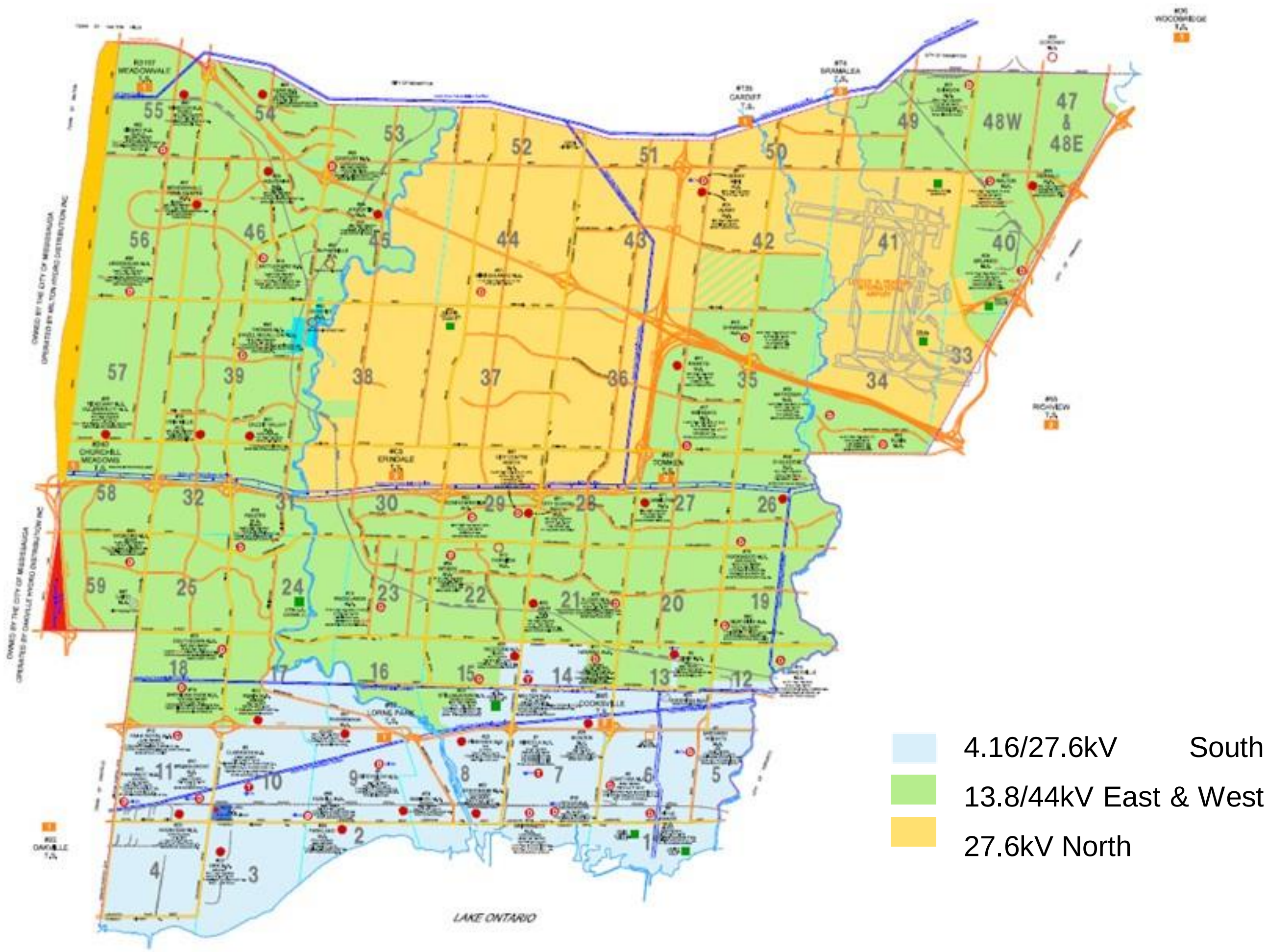
B.2 Mississauga

Mississauga is further divided into North, South, East, and West planning sections. The distribution system has voltages of 4.16/27.6kV,13.8kV/44kV, and 27.6kV. Refer to Figure 5.3.2 - 19.

Figure 5.3.2 - 19: Mississauga Planning Sections



All transformer stations are owned and operated by Hydro One where the voltage is transformed from 230kV to either 44 or 27.6kV.

The Hydro One owned transformer stations are:

- Meadowvale TS
- Churchill Meadows TS
- Erindale TS
- Tomken TS
- Bramalea TS
- Woodbridge TS.
- Oakville TS
- Lorne Park TS
- Cooksville TS

At Alectra Utilities' owned substations the voltage is transformed from 44kV to 13.8kV or from 16/27.6kV to 4.16kV. For the locations of the TS and MS locations, refer to Figure 5.3.2 - 20 to Figure 5.3.2 - 25.

1 **Figure 5.3.2 - 20: Mississauga TS Locations (44 kV, 8/13.8 kV)**

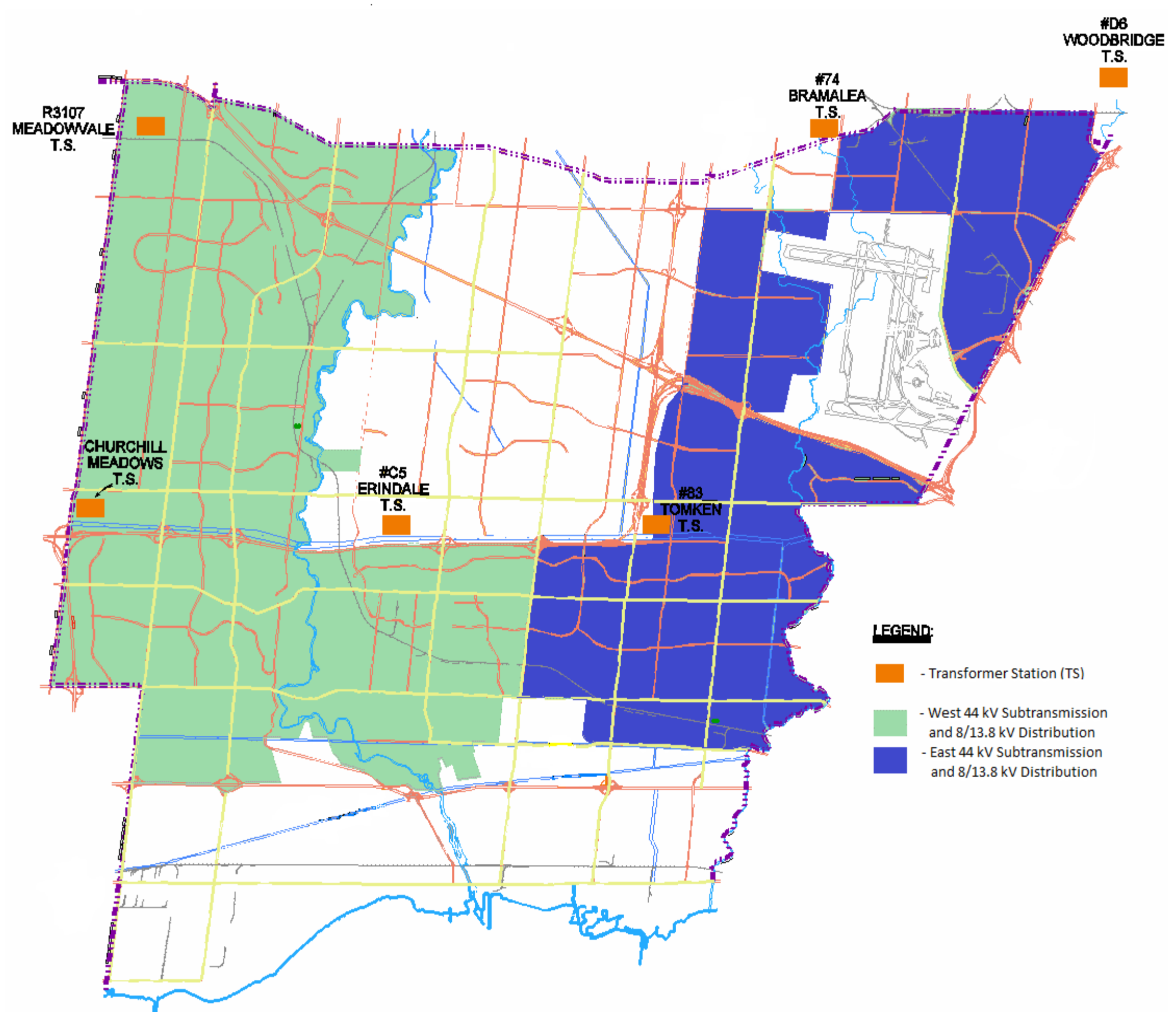


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Figure 5.3.2 - 21: Mississauga TS Locations (16/27.6 kV, 8/13.8 kV)

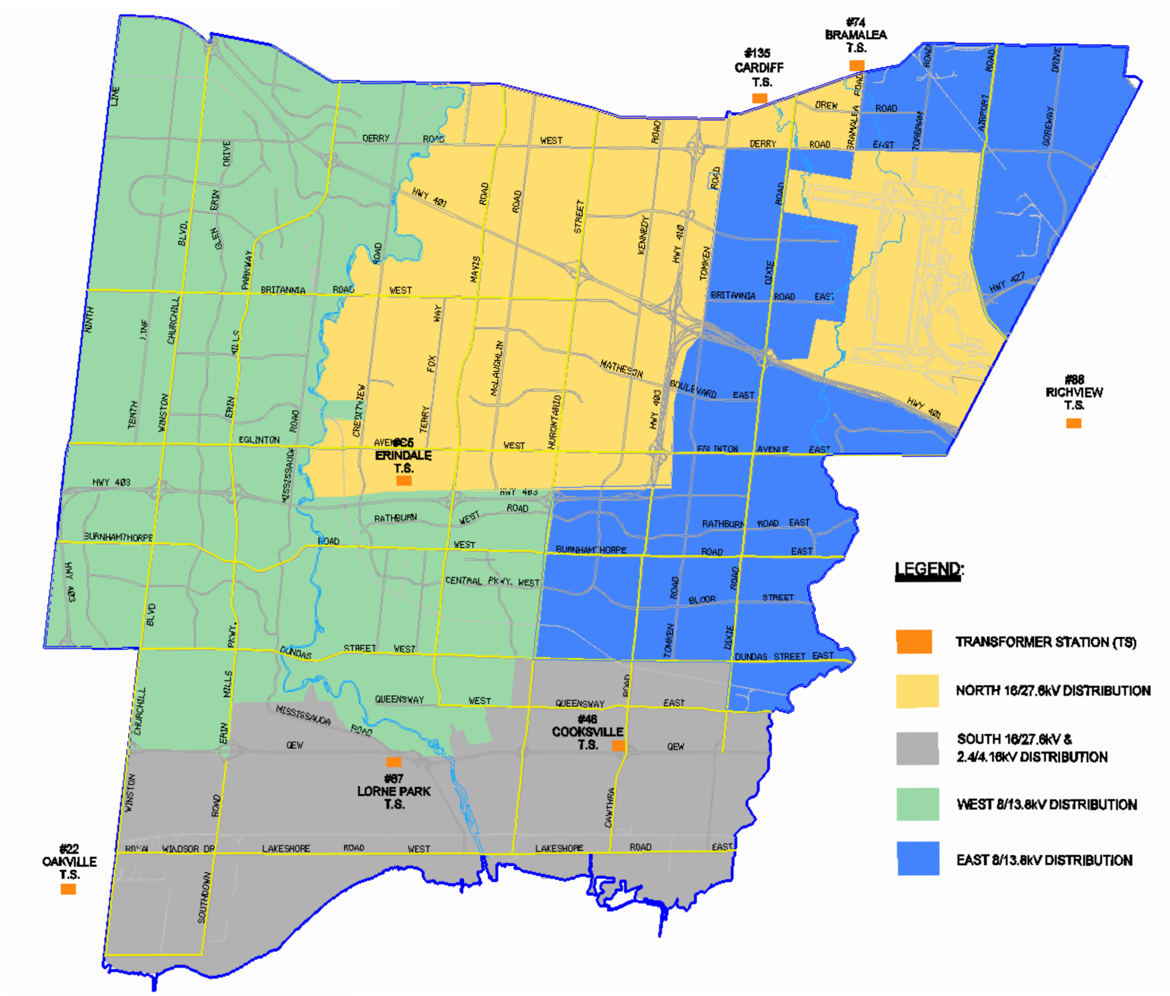


Figure 5.3.2 - 22: Mississauga TS and MS Locations (North 16/27.6 kV)

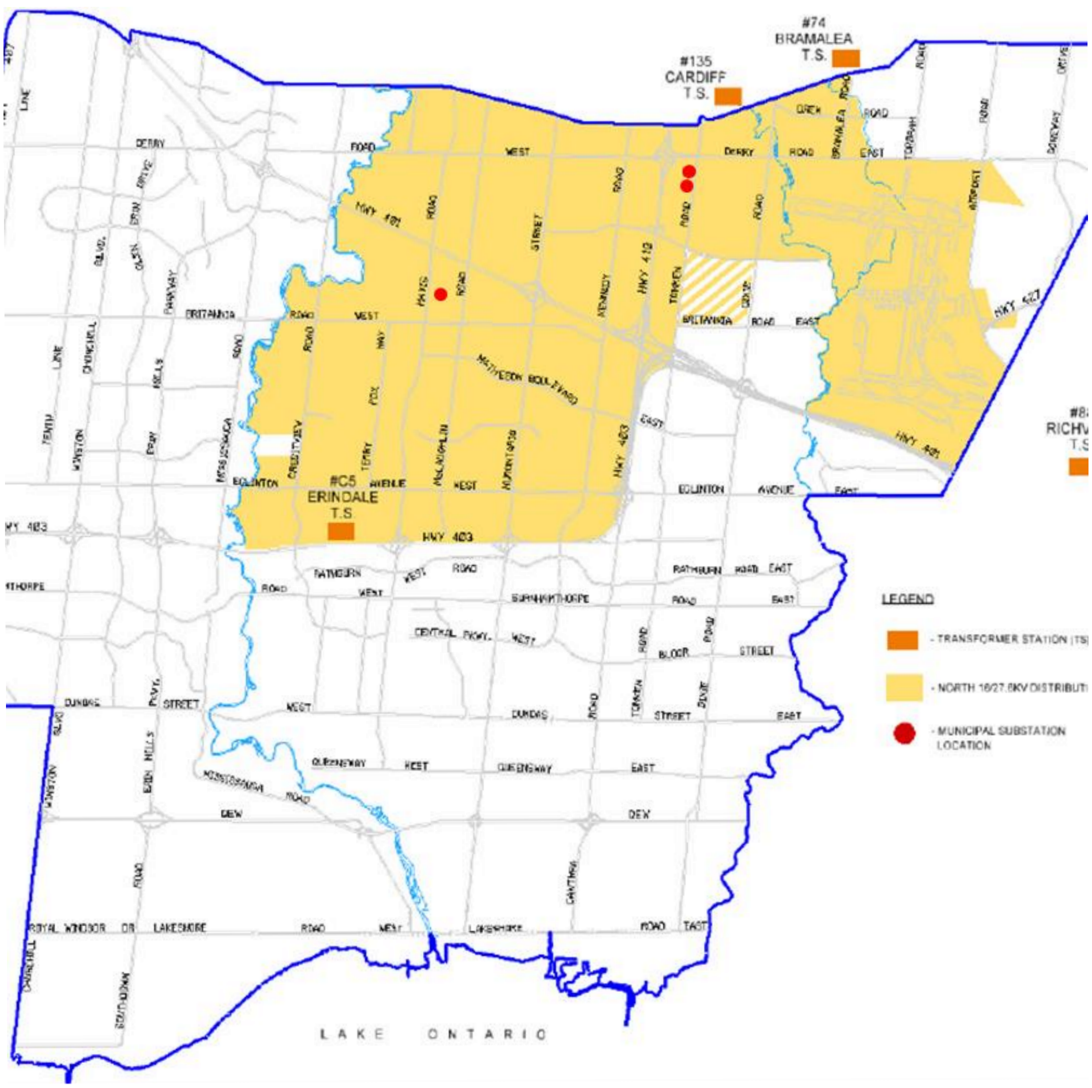


Figure 5.3.2 - 23: Mississauga TS and MS Locations (South 16/27.6 kV)

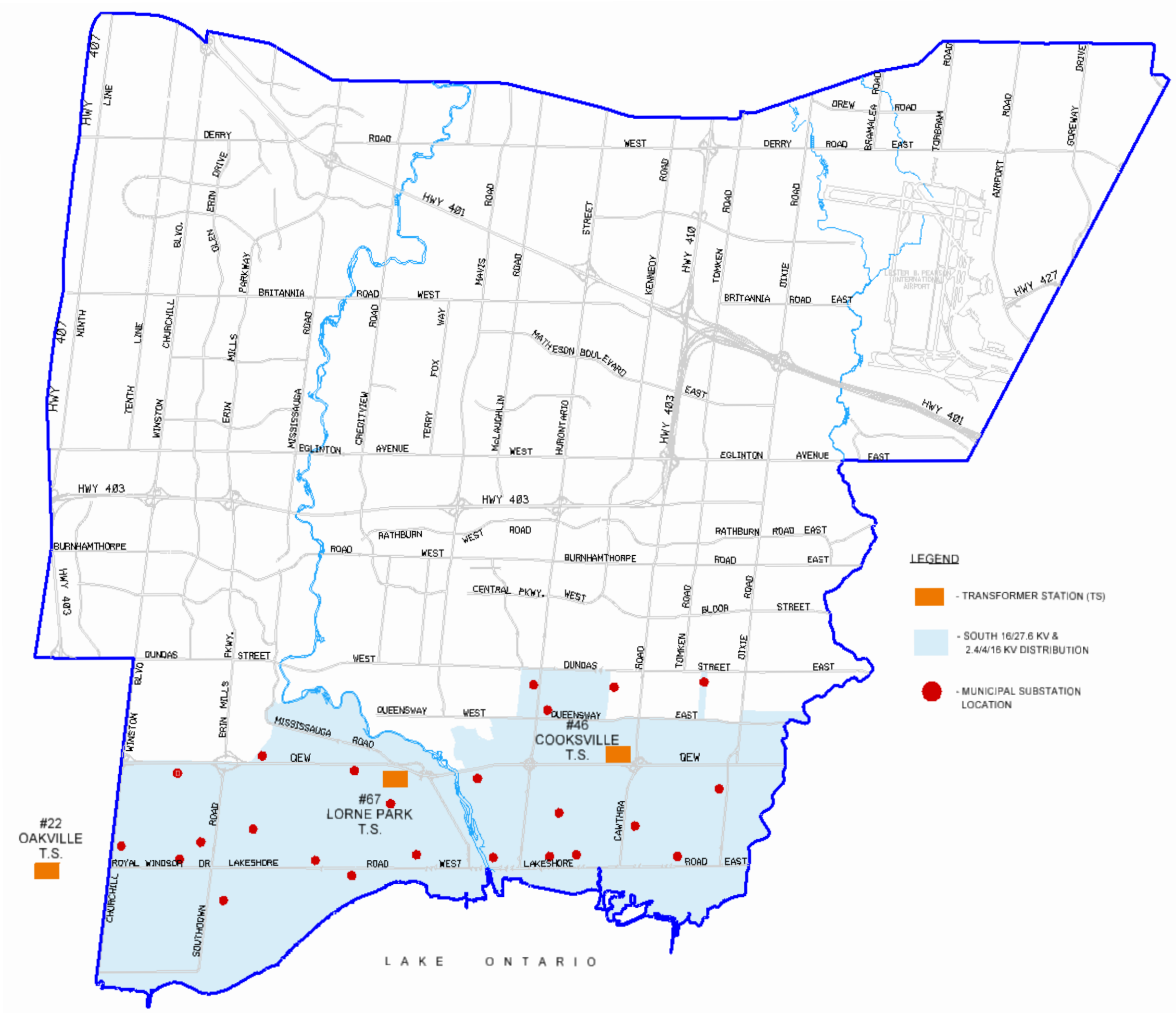


Figure 5.3.2 - 24: Mississauga TS and MS Locations (West 44 kV, 8/13.8 kV)

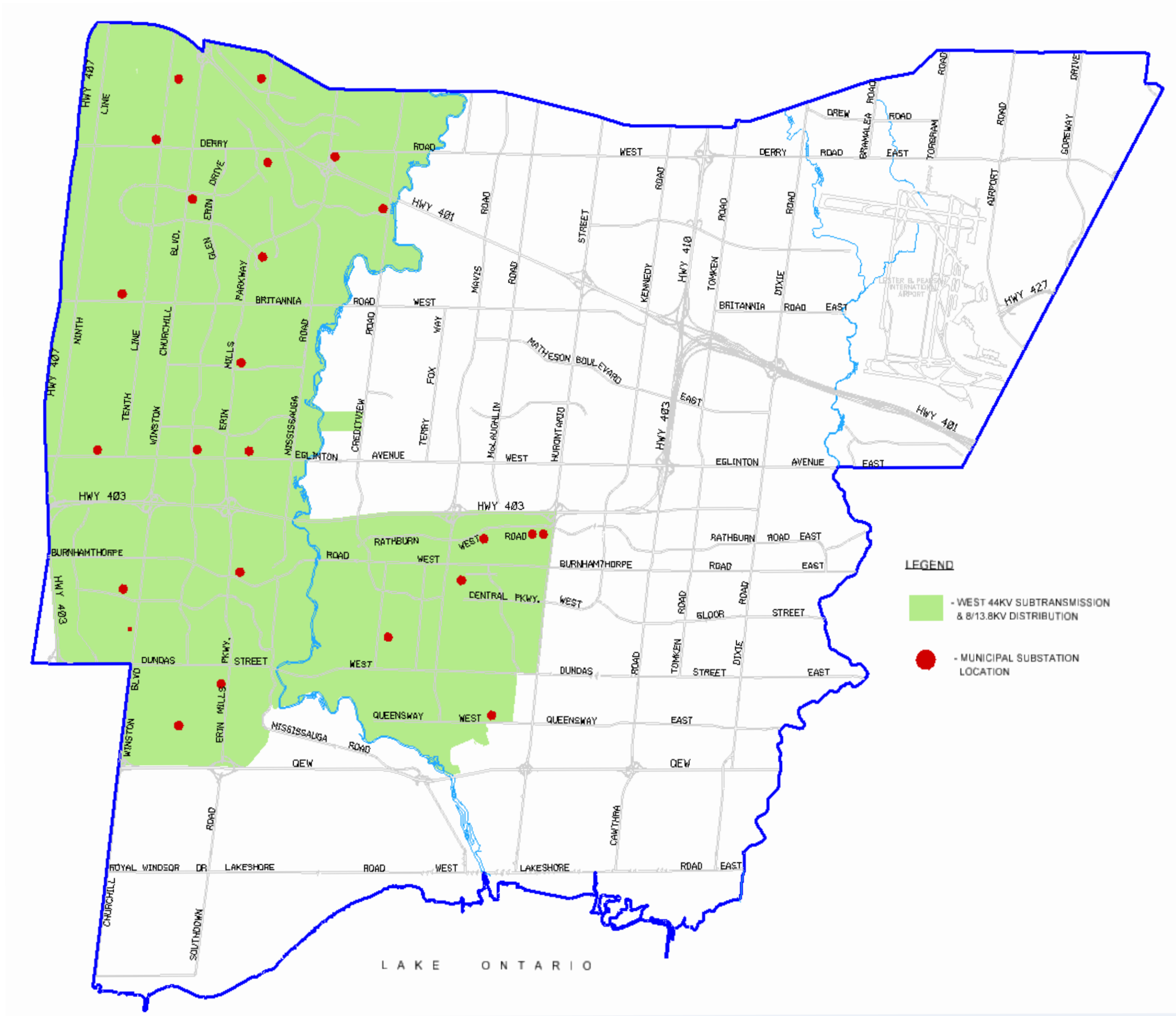
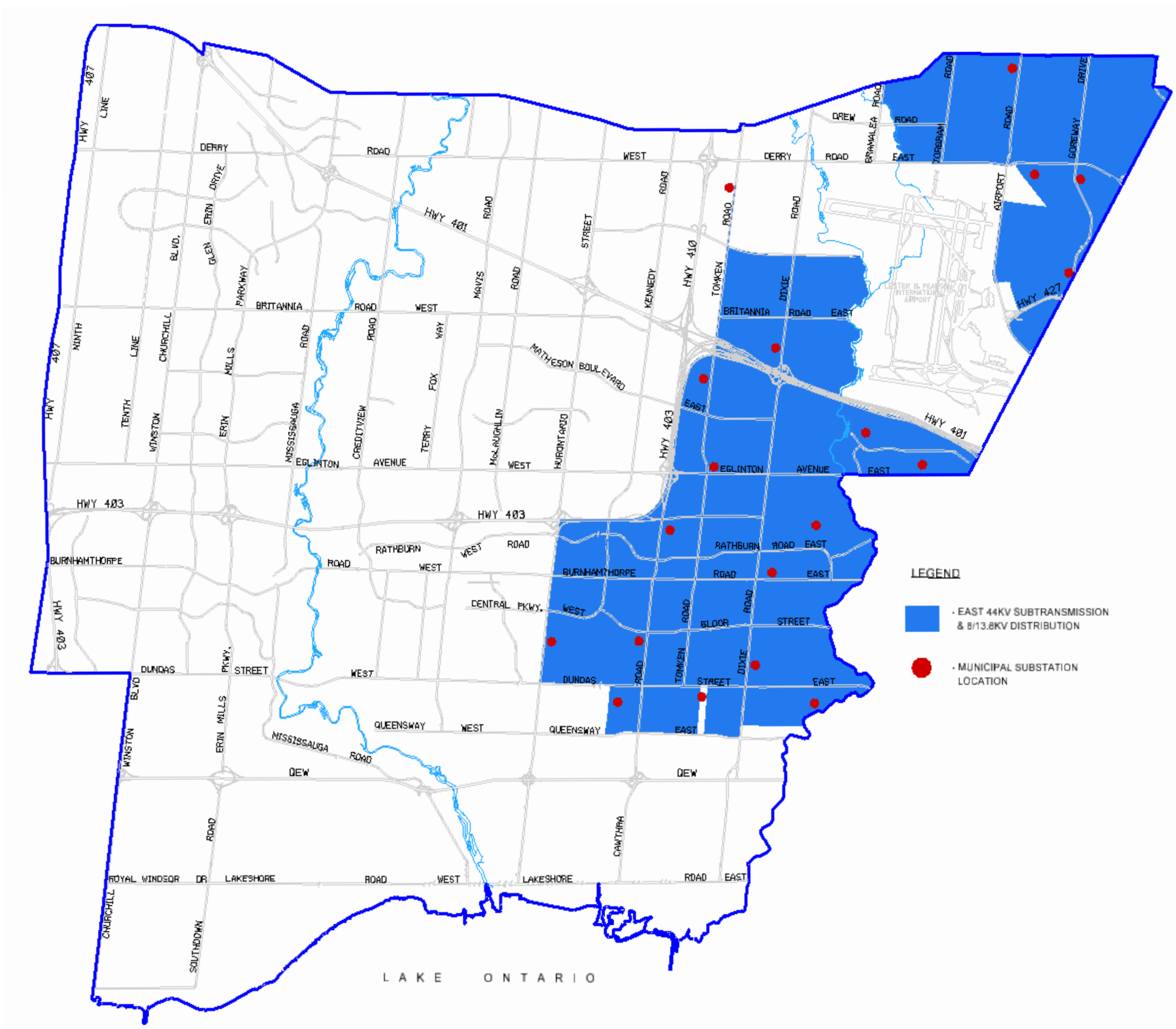


Figure 5.3.2 - 25: Mississauga TS and MS Locations (East 44 kV, 8/13.8 kV)



C Alectra Utilities West

Alectra Utilities West is divided into two regions: Hamilton and St. Catharines.

C.1 Hamilton

Hamilton is supplied by 13 Hydro One owned and operated transformer stations. 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 municipal substations (MS) and multiple customer-owned substations. The municipal substations transform the medium voltage feeders to distribution voltages of 4.16kV and 8.32kV.

There are twenty-three municipal substations in Hamilton; twenty 4.16kV MS's and three 8.32kV MS's. This number will decrease as Voltage Conversion projects proceed to remove the 4.16kV and 8.32kV systems. Refer to Figure 5.3.2 - 26 for a list of stations map highlighting the layout of the area.

Figure 5.3.2 - 26: West (Hamilton) Stations

C.2 St. Catharines

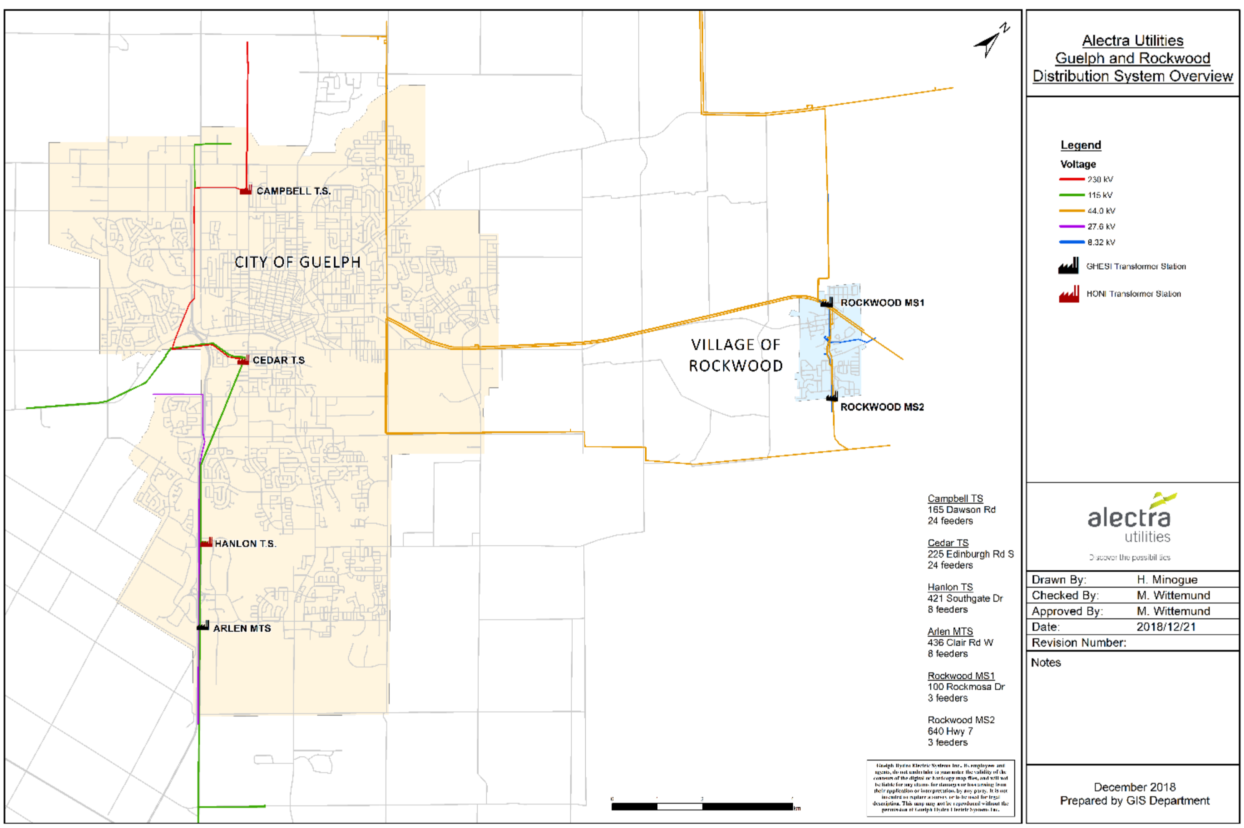
St. Catharines is supplied by four Hydro One transformer stations: Bunting TS, Carlton TS, Glendale TS and Vansickle TS. Hydro One owns and operates these stations and each transformer station supplies multiple 13.8kV busses via 2 or more transformers. From these busses multiple 13.8kV feeders make up the distribution network in St. Catharines. The area has recently completed voltage conversion of the older 4kV assets, unifying the network at 13.8kV in 2018. Refer to Figure 5.3.2 - 27 for the location of MS stations.

Figure 5.3.2 - 27: West (St. Catharines) Stations

D Alectra Utilities SouthWest

SouthWest covers two distinct areas, the City of Guelph and the Village of Rockwood. The City of Guelph is provided by three Hydro One Transformer Stations (Hanlon TS, Cedar TS, and Campbell TS) and one Alectra Utilities owned Transformer Station (Arlen MTS). Cedar TS, Hanlon TS and Arlen MTS 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 Municipal Substations (Rockwood MS1, Rockwood MS2). Both stations are supplied from 44kV feeders originating from Hydro One Fergus TS and their primary distribution feeders are operated at 8.32kV. Refer to Figure 5.3.2 - 28 for location of TS and MS.

Figure 5.3.2 - 28: SouthWest Area



5.3.2.5 ASSET INVENTORY

Table 5.3.2 - 3 and Table 5.3.2 - 4 show the asset inventory of station assets and distribution assets. The age and condition of these assets are included in Chapter 5.3.3.

Table 5.3.2 - 3: Asset Inventory (Stations)

Asset Category	Operating Area				
	Central	East	West	Southwest	Total
Transformer Stations	1	12	0	1	14
Municipal Stations	76	54	23	2	155
All Stations	77	66	23	3	169
TS Transformers	2	24	0	2	28
Spare TS Transformers	1	2	0	0	3
MS Transformers	126	64	49	2	241
Spare MS Transformers	8	9	6	0	23
All Transformers	137	99	55	4	295
TS Circuit Breakers & Reclosers	19	195	0	17	231
MS Circuit Breakers & Reclosers	561	210	261	8	1040
All Circuit Breakers & Reclosers	580	405	261	25	1271
TS Switchgear	1	19	0	1	21
MS Switchgear	232	58	43	2	335
All Switchgear	233	77	43	3	356
HV Primary Switches (Sets of 3)	2	24	0	4	30
TS Station Capacitors	0	11	0	0	11
TS HV PMU ITs	0	36	0	0	36
TS SS Transformers	2	20	0	2	24
TS P&C Relays (Microprocessor)	32	304	0	19	355
TS P&C Relays (Solid State)	0	48	0	0	48
TS P&C Relays (Electromechanical)	0	26	0	0	26
All TS P&C Relays	32	378	0	19	429
MS P&C Relays (Microprocessor)	367	351	141	10	869
MS P&C Relays (Solid State)	251	3	0	0	254
MS P&C Relays (Electromechanical)	380	3	56	0	439
All MS P&C Relays	998	357	197	10	1562
All P&C Relays	1030	735	197	29	1991

Table 5.3.2 - 4: Asset Inventory (Distribution Assets)

Asset Category	Operating Area				
	Central	East	West	SouthWest	Total
Padmounted Transformers	31,337	37,525	6,593	4,032	79,487
Pole-mounted Transformers	7,713	8,620	13,812	1,978	32,123
Vault Transformers	5,208	3,897	4,034	206	13,345
Switchgear Total	1,182	1884	219	104	3,389
OH Switches	831	1,394	1,243	421	3,889
OH Conductors (length, km)*	6,075	6,710	2,546	1,069	16,400
Wood Poles	19,326	36,260	40,877	9,106	105,569
Concrete Poles	12,947	1,210	10,369	814	25,340
UG Primary XLPE Cables (length, km)*	9,776	8,380	2,393	1,089	21,638
UG Primary PILC Cables (length, km)*	1	0	409	0	410
UG Primary EPR Cables (length, Km)*	0	0	91	0	91
UG Primary Cables Total (length, km)*[47]	9,777	8,380	2,893	1,089	22,139

5.3.2.6 ASSET CAPACITY UTILIZATION

Alectra Utilities harmonized system planning philosophy has been developed as the result of a comprehensive review of planning criteria, and the practices and guidelines of the predecessor utilities. Best practices were adopted, while still respecting legacy system constraints.

The new system planning philosophy has been adopted, and planning practices have been unified for all rate zones. The new planning philosophy takes into account service reliability, cost, risks, and constraints of legacy utility systems.

The planning philosophy contains the methodology, technical applications, and other relevant topics associated with the distribution system planning process. Practices, guidelines and criteria fundamental to ensuring the timely augmentation of Alectra Utilities' distribution system to meet customer load growth and contingency requirements are outlined.

Below are the guiding principles for Alectra Utilities' system planning, feeder and station capacity thresholds.

[47] Refers to conductor length and not circuit length.

12. 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 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.
13. 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.
14. 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.
15. Alectra Utilities operates primary feeders (44/27.6/13.8/8.32/4.16kV) under normal conditions (summer peak) to a maximum loading that isthe lesser of 2/3rd egress cable rating or 2/3rd of the 600 amp contingency rating.
16. Alectra Utilities operates primary feeders under contingency conditions to a maximum loading rating of the lesser of the egress cable or 600-amp.
17. 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).
18. Where a transmission system connected transformer station is required, Alectra Utilities plans to continue building Dual Element Spot Network ("DESN") transformer stations.
19. Alectra Utilities utilizes a 10-day Limited Time Rating (10-Day LTR) for transformer station capacity planning criteria.
20. 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 exceeds 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.

21. Alectra Utilities will maintain a spare transformer (i.e., a mobile unit with multiple primary and secondary configurations) to mitigate the risk of a prolonged station transformer loss.
22. Alectra Utilities will limit the construction of four-circuit pole lines by using two separate double-circuit pole lines on both sides of a roadway, with switching ties for back-up. Where dual pole lines are not permitted, Alectra Utilities will pursue the strategic placement of switching ties and concrete poles, or where prudent, the undergrounding of the feeders.

Alectra Utilities uses a deterministic N-1 philosophy for planning the Transformer and Municipal substations, which is consistent with practices adopted by utilities across Canada. The following are the guidelines for determining the transformer loading for the Transformer and Municipal substations.

A Station Utilization

A.1 Transformer Stations Utilization

The transformer limited time rating (LTR)[48] is used as transformer loading guideline. The optimal ratio of peak to limited time rating (LTR) is 90% to 95%. This leaves capacity for high loading periods and to provide contingency capacity. Values that exceed 95% are not desirable.
The LTR rating is used as the transformer station loading guideline for the following reasons:

- If one transformer fails in a typical dual element spot network (“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 10 days.
- Replacing the failed transformer with a system spare transformer takes approximately 10 days; and
- For a transformer outage longer than 10 days, the transformer loading must be brought to its base rating. This can be accomplished by load transfers of above name rating to adjacent stations or by load shedding.

[48] 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.

Figure 5.3.2 - 29 and Figure 5.3.2 - 30 illustrates the utilization of TS in 2018, with growth projections to 2024 for the TS supplying the Alectra Utilities' service area.

Figure 5.3.2 - 29: Alectra Utilities' Owned TS Utilization

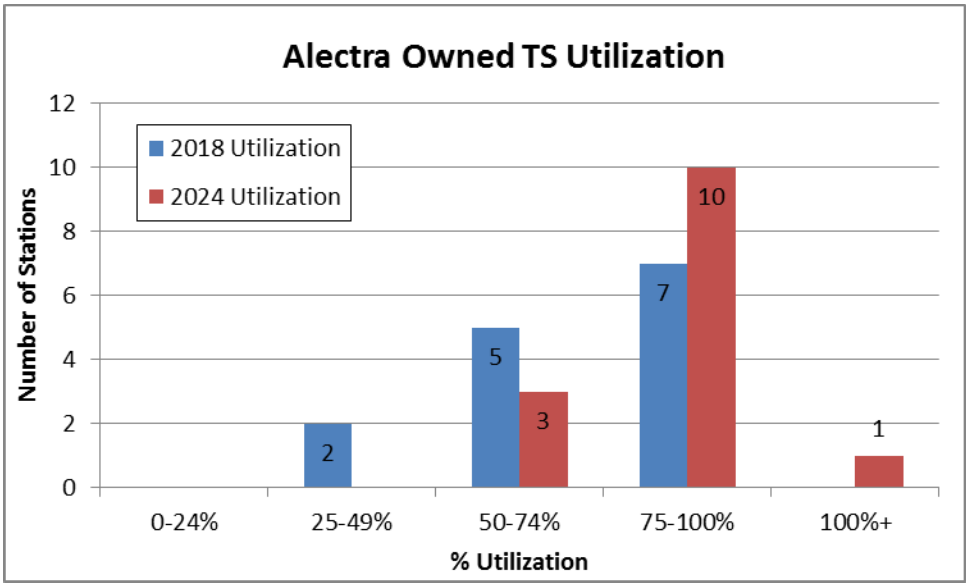
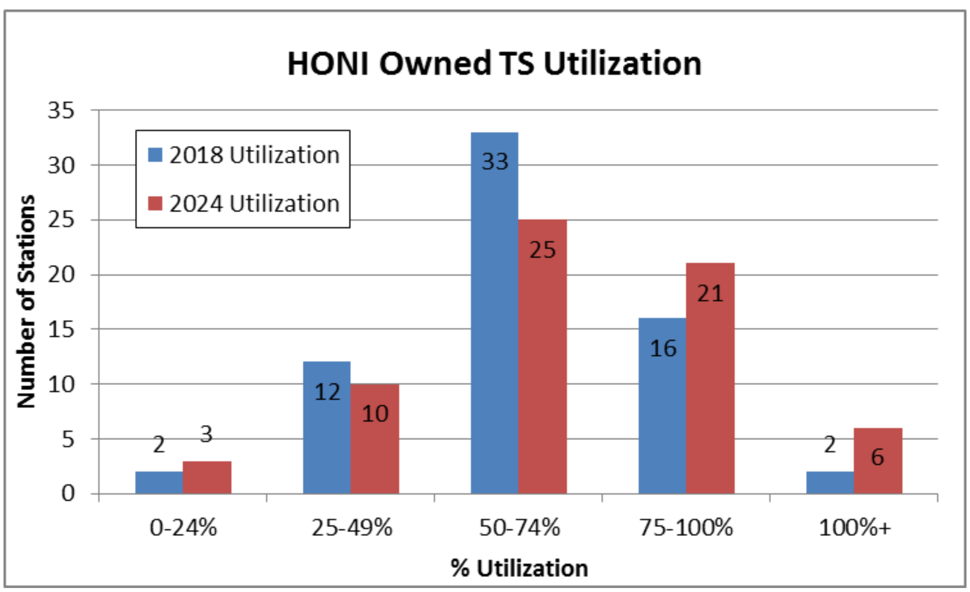


Figure 5.3.2 - 30: HONI Owned TS Utilization



For the two Alectra Utilities owned stations where the utilization is low; those are new stations and new developments in the area will be adding capacity in the near to long term. One Alectra

Utilities owned station TS (Jim Yarrow) is projected to be over the LTR by 2024. This station can be offloaded by Pleasant TS.

There are six HONI owned 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 terms needs in the area.

In summary, the Transformer assets are, or are soon to be, at optimal limits. They are being prudently utilized.

A.2 Municipal Substations Loading

Municipal substations are supplied from 44kV, 27.6kV or 13.8kV circuits, and step down the voltage to one of the three distribution levels: 13.8kV, 8.32kV, and 4.16kV. Each substation typically has 2 to 4 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 via feeder ties.

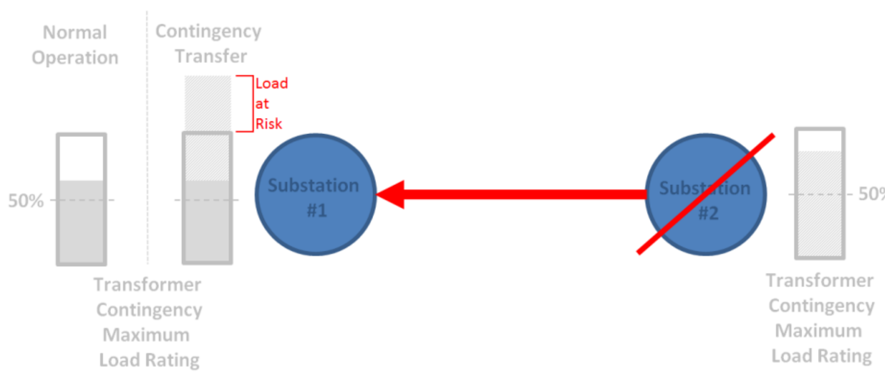
A deterministic approach requires that supply is maintained during any N-1 contingency condition. This requirement extends to substation planning to ensure that load associated with the loss of the largest transformer element in the substation network can be maintained by adjacent substations while remaining within the substations' transformers contingency rating. The contingency rating is determined by the cooling capabilities of the transformer, and is equivalent to the highest cooling rating; i.e., ONAN (100% of base rating) for self-cooled transformer units, ONAF (133% base rating) or ONAF/ONAF (166% of base rating) for transformer units with single and dual stage fans, respectively. The ONAN is the base rating of the transformer without additional cooling, while ONAF or ONAF/ONAF is the maximum permissible loading with single or dual stage fans on the transformer.

Following the N-1 contingency criterion, the minimum substation transformer network configuration required to maintain load across the system corresponds with two loading scenarios: Two Substation Network or Three Substation Network. These are described in further detail, below.

A.2.1 Two Substation Network

In a two substation network configuration with similar rating, the N-1 contingency criterion is only satisfied if the substation transformers in the network are never loaded beyond 50% of the contingency rating. 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, as illustrated in Figure 5.3.2 - 31, below.

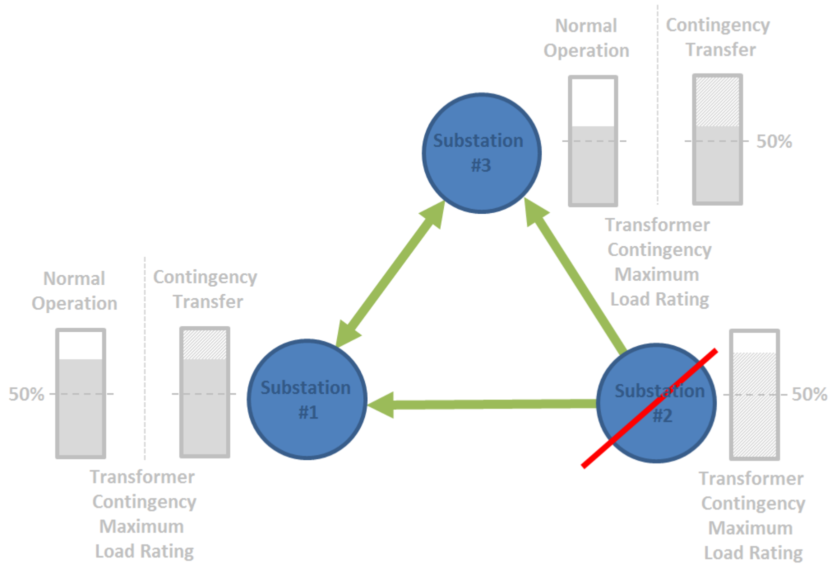
Figure 5.3.2 - 31: Contingency N-1 Criterion for Two Substation Network



A.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 - 32 below.

Figure 5.3.2 - 32: 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 - 33 illustrates the MS loading in 2018 and 2024 relative to the maximum rating.

Figure 5.3.2 - 33: Alectra Utilities Municipal Station Utilization

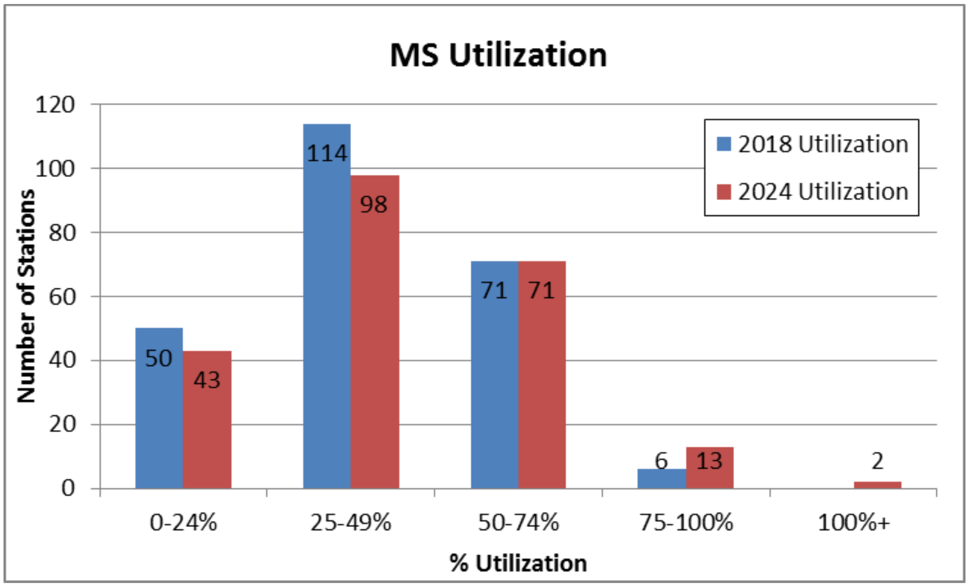


Figure 5.3.2 - 33 illustrates that the transformers are at optimal loading conditions to accommodate the contingency transfers. There will be two stations, one in Bradford and one in Alliston, which will be over the maximum rating. Alectra Utilities will be required to augment the capacity at these stations.

Typical transformer station construction takes 3-5 years from inception to completion, depending on whether adequate transmission facilities are available. Typical municipal substation projects take 2-3 years from inception to completion. Alectra Utilities' goal is to identify transformer and municipal substation 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. Please refer to Chapter 5.2.1 section for load forecasting process.

Investments to support the expansion of Transformation (TSand MS) system are detailed in Appendix A13 - Stations Capacity.

B Feeder Loading

Alectra Utilities' service territory is supplied by 1,406 feeders. Table 5.3.2 - 5 shows the inventory of feeders as of 2018.

Table 5.3.2 - 5: Asset Inventory (Distribution Assets)

No. of Feeders				
4.16kV	8.32kV	13.8kV	27.6kV	44kV
300	16	701	290	99

Alectra Utilities' planning philosophy 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 2/3rd egress cable rating or 2/3rd 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 amps.

Alectra Utilities' system configuration consists of open looped network design with multiple feeders interconnected via normal open points. The 2/3rd 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.

Alectra Utilities conducts annual load forecasting and load balancing to ensure that feeders stay within their normal loading limits. Additional feeder projects proposed each year is paced to match timing of known development, considering available capacity, and expected load growth, net of conservation and demand side management. Alectra Utilities designs and plans projects using a phased approach based on feeder loading, funding availability and customer development progress, which allows the utility to pace investments just-in-time for connecting new developments while ensuring stable rates and maintenance of reliability for existing customers in the area.

Some new lines require significant capital investment and take several years to build. They will be built in phases to minimize the impact on rates and resources.

Figure 5.3.2 - 34 to Figure 5.3.2 - 38 shows the asset utilization of feeders and the associated voltage class relative to the planning limits.

Figure 5.3.2 - 34: 4.16kV Feeder Utilization

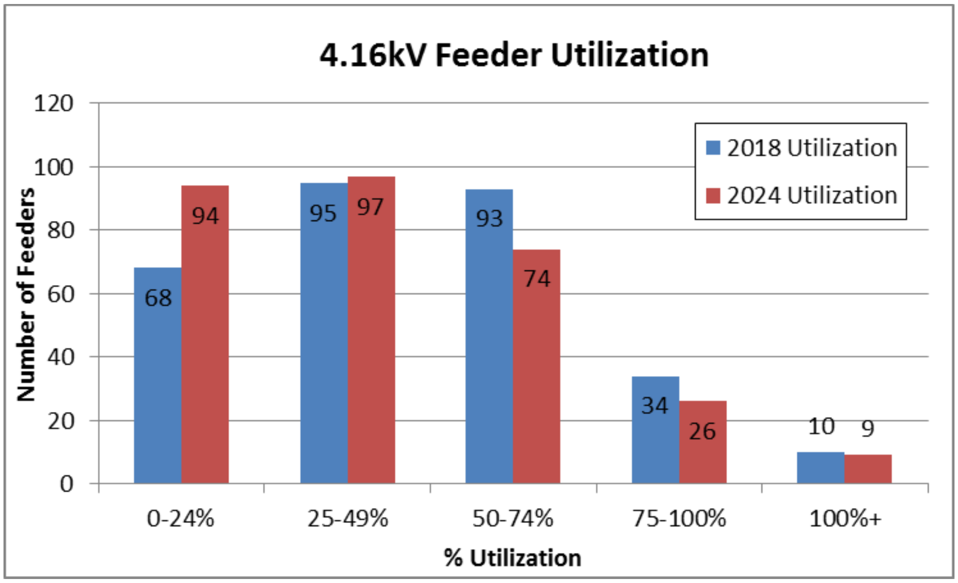


Figure 5.3.2 - 34 shows the utilization of feeders for 4.16kV relative to the planning limit. The 4.16kV is the lowest distribution voltage class in Alectra Utilities' service territory. From 2020-2024, the load growth on these feeders is projected to be minimal. The majority of these feeders are within the planning limit, and within 2/3rd of the loading criteria, and therefore during contingencies, loads can be transferred between the feeders. By 2024, 43 feeders will be decommissioned due to the voltage conversion program. There are no anticipated capital investments related to 4.16kV feeder expansion over the DSP period.

Figure 5.3.2 - 35: 8.32kV Feeder Utilization

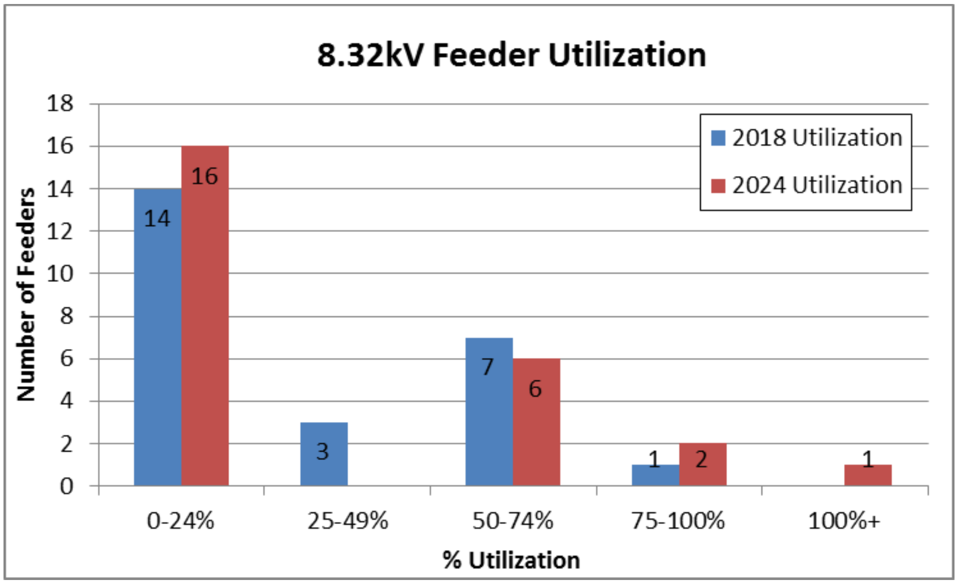
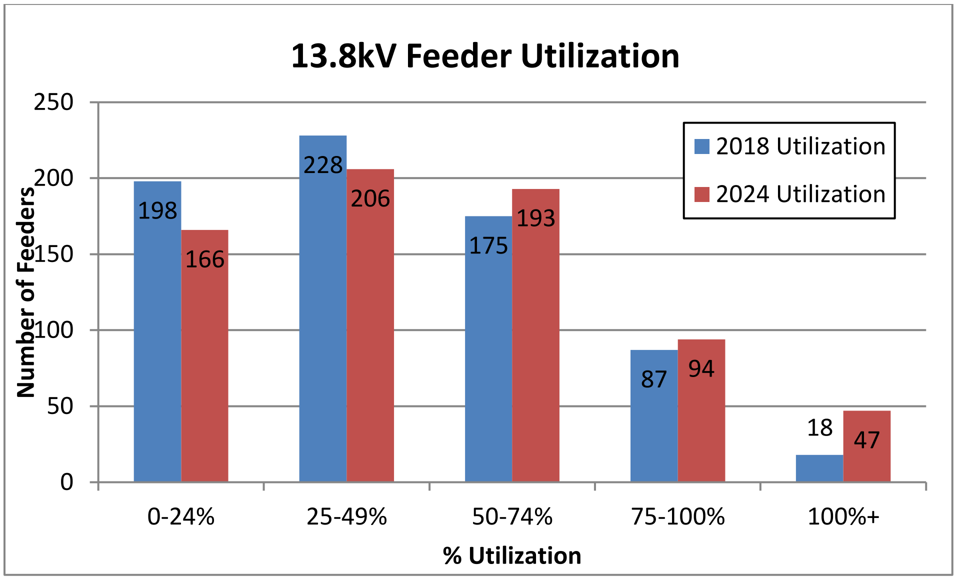


Figure 5.3.2 - 35 illustrates the utilization of the 13.8kV feeders. None of the 8.32kV feeders are over the planning limit. By 2024, one feeder will be over the planning limit due to projected load growth. Similar to the 4.16kV, Alectra Utilities plans to convert the 8.32kV to 13.8kV or 27.6kV. By 2024, seven feeders will be decommissioned. There are no anticipated capital investments related to 8.32kV feeder expansion over the DSP period.

1 **Figure 5.3.2 - 36: 13.8kV Feeder Utilization**



2

3 Figure 5.3.2 - 36 illustrates the utilization of the 13.8kV feeders. 18 feeders are currently over the
4 planning limit, and due to projected load growth, 47 feeders will be over 100% of planning limit by
5 2024. Alectra Utilities will manage the feeder loading by load balancing through distribution
6 changes, such as adding additional tie points and sectionalizing switches. Alectra Utilities also
7 plans to build additional feeders to augment existing feeders. The details can be found in
8 Appendix A12 – Lines Capacity.

Figure 5.3.2 - 37: 27. kV Feeder Utilization

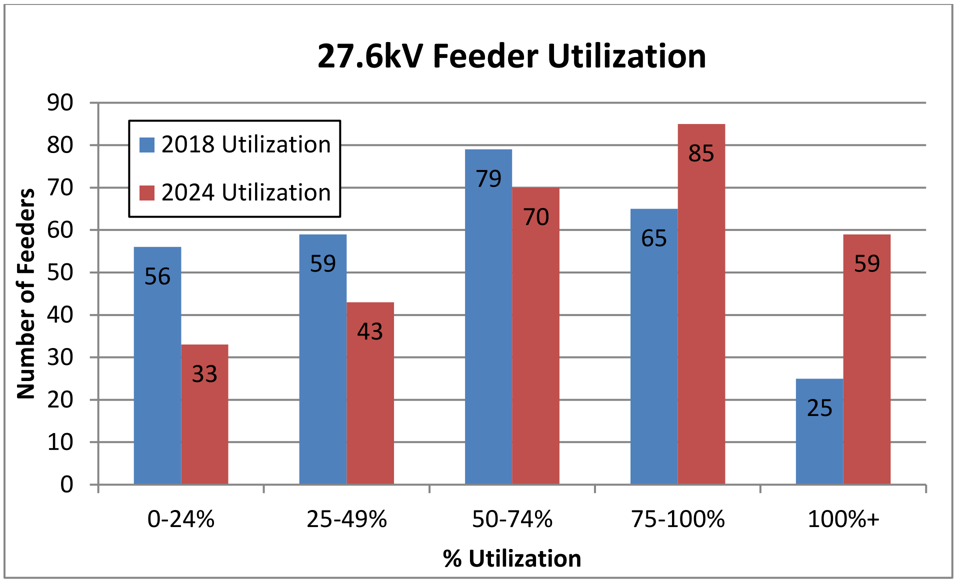


Figure 5.3.2 - 37 illustrates the utilization of the 27.6kV feeders. Twenty-five feeders are currently over the planning limit, and due to projected load growth, 59 feeders will be over the planning limit by 2024. Alectra Utilities will manage feeder loading by load balancing through distribution changes, such as adding additional tie points and sectionalizing switches. Alectra Utilities also plans to build additional feeders to augment existing feeders. The details can be found in Appendix A12 – Lines Capacity.

Figure 5.3.2 - 38: 44kV Feeder Utilization

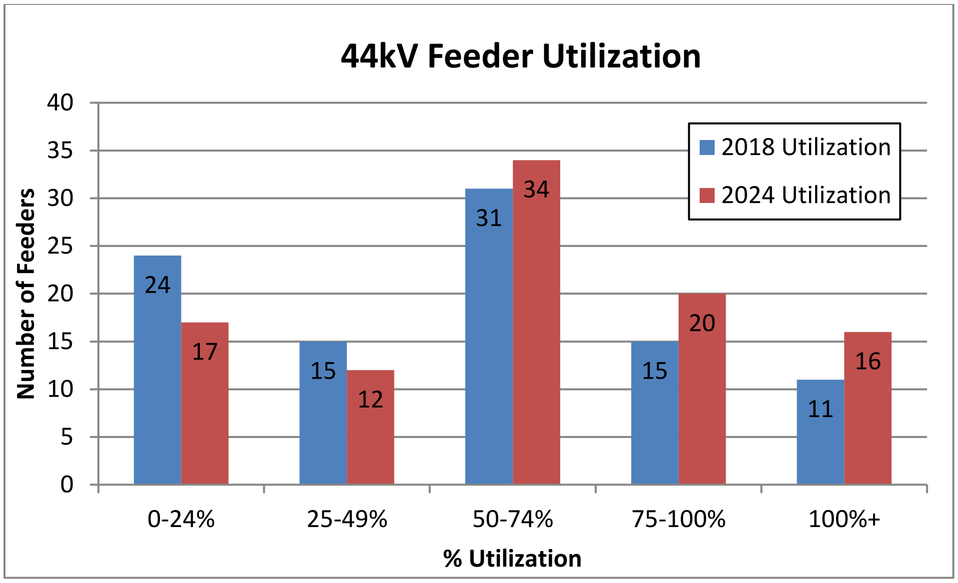


Figure 5.3.2 - 38 illustrates the utilization of the 44kV feeders. Eleven feeders are currently over the planning limit, and due to projected load growth, 16 feeders will be over the planning limit by 2024. Alectra Utilities will manage the feeder loading by load balancing through distribution changes, such as adding additional 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 12 – Lines Capacity.

The individual TS, MS and feeder loading with actual 2018 and forecasted 2024 peak for each of the operating areas has been provided in Appendix O. Please refer to:

- Appendix O-01 - Stations and Feeder Loading Table – East
- Appendix O-02 - Stations and Feeder Loading Table - Central
- Appendix O-03 - Stations and Feeder Loading Table - West
- Appendix O-04 - Stations and Feeder Loading Table - Southwest

C Building Facilities

Table 5.3.2 - 6 details the current-state of facility capacity (in square feet) and use at Alectra Utilities.

Table 5.3.2 - 6: Current Building Envelopes

Address	City	Region	Building Type	Building (Sq. Ft)
2185 Derry Rd West	Mississauga	Central	Head Office	80,000
3240 Mavis Road	Mississauga	Central	Service Centre	125,000
175 Sandalwood Parkway West	Brampton	Central	Service Centre	154,000
161 Cityview Blvd	Vaughan	East	Office Building	92,000
80 Addiscott Court	Markham	East	Service Centre	107,000
55 Patterson Road	Barrie	East	Service Centre	81,832
9801 Jane Street	Vaughan	East	Office Building	22,601
55 John St North	Hamilton	West	Office Building	159,987
340 Vansickle Road	St. Catharines	West	Service Centre	63,367
450 Nebo Road	Hamilton	West	Service Centre	107,500
395 Southgate Dr.	Guelph	Guelph	Service Centre	104,000

5.3.3 ASSET LIFECYCLE OPTIMIZATION

Section 5.3.3 of the DSP outlines Alectra Utilities' life cycle optimization approach for its distribution system assets. Specifically, this section outlines the replacement, refurbishment and maintenance strategies and practices that the utility applies to major asset classes to sustain and maximize asset value. Lifecycle optimization practices for general plant assets (e.g., fleet and IT) are discussed in section 5.4.3.

5.3.3.1 OVERVIEW

In managing its distribution system assets, Alectra Utilities' main objective is to optimize asset performance with due regard for system reliability, safety, cost, and customer service requirements. More specifically, the utility's approach to asset lifecycle optimization focuses on deriving maximum value from its assets and minimizing total cost of asset ownership in a sustainable manner, while delivering reliable service to its customers. In doing so, Alectra Utilities considers a range of input parameters (including asset condition, asset functionality, loading, current standards, and risk of failure) to determine if an asset is suited for continued service, or requires refurbishment or replacement.

The integrated practices that underpin the utility's asset lifecycle optimization approach involves annual inspection, testing and maintenance programs (as discussed below), as well as resulting capital investment planning (including business case development) and investment portfolio optimization (as discussed in sections 5.3.1 and 5.4.1). Through its effective inspection, testing and maintenance programs, Alectra Utilities is able to adequately capture asset-related information to properly assess and prioritize asset replacement and refurbishment while balancing operational maintenance costs and risks. At a high level, these programs include the following:

- Annual overhead distribution system inspections for transformers, poles, insulators, switches, arrestors, and hardware attachments (e.g., guy wires, cross arms, and ground wires).
- Annual 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.

- Alectra Utilities normally performs station asset inspections on a monthly basis, with more detailed inspections, testing, and maintenance activities taking place annually. In the West, Central, South, and Southwest operating areas, observations and test results from the inspections, testing, and maintenance activities are recorded using a combination of hard copy and soft copy reports and observations are retained in different file systems. In the East operating area, inspections, testing, and maintenance observations are entered into a Computerized Maintenance Management System ("CMMS").[49]

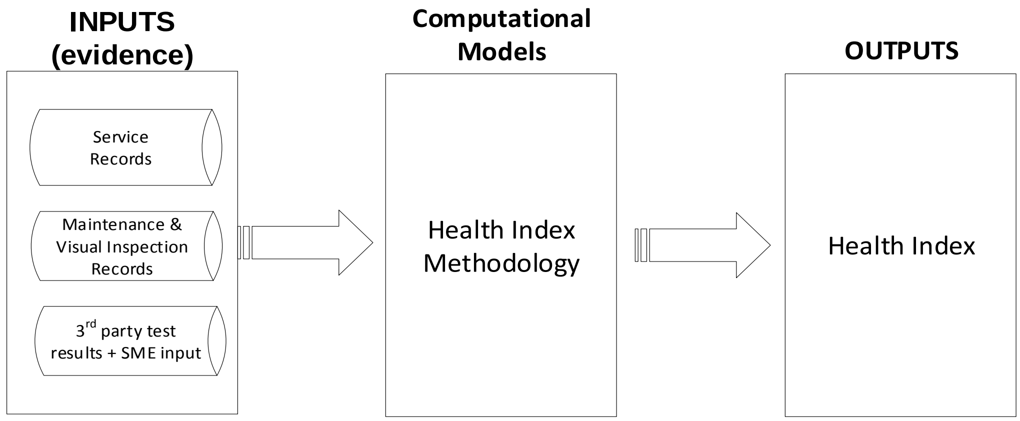
Results from inspection and testing programs are important inputs to Alectra Utilities' Asset Condition Assessment ("ACA")[50], which ultimately establishes Health Index ("HI") values for eleven major asset groups[51].

The ACA is an analytical model that quantifies asset condition based on weighted inputs in a consistent manner. The number and type of input parameters (based on applicable service records, maintenance and inspection records, third party test results, and subject matter expert ("SME") input) vary depending on the specific asset class and available data. The weighting of input parameters is based on the asset class, industry guidelines, and Alectra Utilities' experience.

HI results support the effective planning and prioritization of asset refurbishments and replacements. A planned replacement strategy driven by HI ensures that investments are directed toward the appropriate needs. Figure 5.3.3 - 1 illustrates the main components of the HI model.

[49] The CMMS receives real-time operational SCADA data, inspection data, test data, and for some transformers, real time dissolved gas levels, which enable the flagging of station asset maintenance requirements based on criteria set by Alectra Utilities' Stations Sustainment Department. Outputs from the CMMS are available to operational divisions (such as Station Sustainment and Protection and Control) for purposes of responding to maintenance requirements that are triggered in respect of specific assets. Efforts are currently underway to integrate this application for all stations across Alectra Utilities' service territory
[50] Refer to DSP Appendix D - Asset Condition Assessment - 2018
[51] Distribution assets assessed: wood poles, concrete poles, overhead primary conductors, pole mounted load interrupting switches, underground medium-voltage power cables, pad mounted transformers, vault type transformers, pad mounted switchgear. Station assets assessed: power transformers, circuit breakers station class switchgear

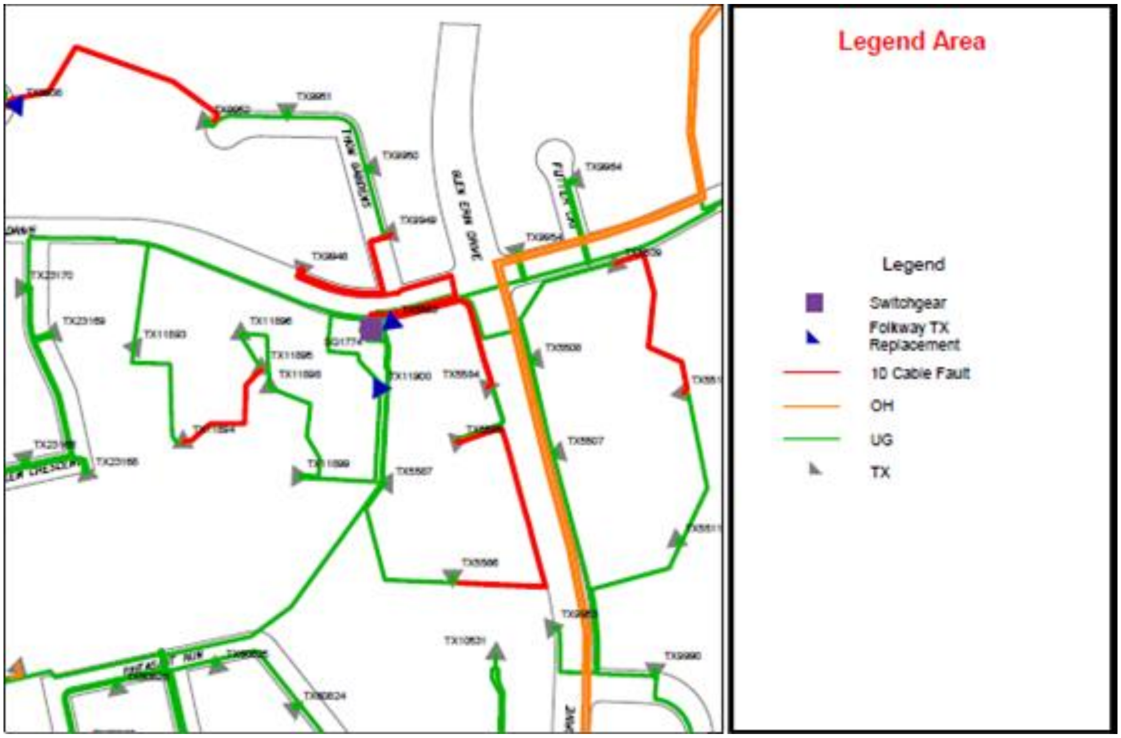
Figure 5.3.3 - 1: Health Index Model



The information that Alectra Utilities derives from its inspection and testing programs are imported to its Geographical Information System ("GIS"). Overhead and underground plant is inspected and evaluated against pre-set criteria, and results are recorded both manually on hard copies and electronically using portable digital devices. Crews use computer tablets to carry out, and capture detailed results from, inspections for each asset group. The results are validated against the GIS asset records using an automated quality assurance and quality control process, and any validation exceptions are identified and corrected prior to import into the GIS. This ensures that Alectra Utilities is using the most accurate asset data when planning its asset lifecycle optimization approach.

Alectra Utilities leverages the information obtained via inspections and testing to generate detailed maps (using Microsoft Power BI) that display inspection results. These specialized maps aid the identification of asset clusters involving poor inspection results by asset type. Using an overlay methodology, Alectra Utilities is able to display multiple asset types and the corresponding inspection results, enabling engineering staff to assess areas of the system where rebuild options may be preferable (compared to targeted asset replacement), and determine when to implement maintenance activities to maximize asset useful life. Figure 5.3.3 - 2 below is an excerpt from an overlay map. The map excerpt identifies cable segments in Very Poor condition (red line), which have experienced multiple cable faults as well as padmounted transformer locations having a Very Poor HI (blue triangles), identified to be replaced.

Figure 5.3.3 - 2: Overlay map identifying Very Poor cable segments (Red Lines) and Very Poor padmounted transformers (Blue Triangles)



The HI results of the ACA are shown in Table 5.3.3 - 1. This table illustrates the HI of each major asset class and the average age of assets in each class and identifies that a significant population of primary XLPE cables have a Very Poor HI.

Table 5.3.3 - 1: Health Index by Asset Class with Average Age

Asset Class	Unit measure	HI %					Average Age
		VP	P	F	G	VG	
Distribution UG Primary EPR Cables	km	0.00	0.00	0.00	0.00	100.00	4
Distribution UG Primary PILC Cables	km	2.68	1.46	0.97	2.19	92.70	36
Distribution UG Primary XLPE Cables	km	11.07	3.51	4.41	6.70	74.30	22
Distribution Concrete Poles	unit	1.80	3.30	5.43	37.95	51.52	23
Distribution Wood Poles	unit	4.63	3.47	16.62	38.13	37.15	28
Distribution Overhead Conductors	km	1.36	0.96	0.48	0.40	96.81	25
Distribution Overhead Switches	unit	6.56	1.93	1.62	2.39	87.50	19
Distribution Pad-mounted Switchgears	unit	8.35	8.94	5.05	9.06	68.60	44
Distribution Vault Transformers	unit	1.35	0.77	21.63	2.78	73.47	27
Distribution Pole-mounted Transformers	unit	1.57	1.59	5.93	34.64	56.27	20
Distribution Pad-mounted Transformers	unit	2.12	0.01	13.53	18.54	65.80	17
Stations Switchgear	unit	0.00	10.11	22.75	53.37	13.76	21
Stations Circuit Breakers	unit	4.03	28.02	1.03	19.34	47.59	20
Stations Power Transformers	unit	0.00	11.53	0.68	17.97	69.83	25

5.3.3.2 ASSET REPLACEMENT PRACTICES

Alectra Utilities' asset replacement strategy includes a combination of planned and reactive replacement practices. Asset replacement decisions are driven by a number of considerations and constraints, including asset failure, failure risk (i.e., due to asset deterioration), functional obsolescence, asset performance trends, as well as alignment with applicable standards, capacity requirements, and third party requests (e.g., roadway improvements).

Alectra Utilities' distribution system includes certain asset populations that are high volume but have a low failure impact, and other asset populations that are low volume but have a high failure impact. Accordingly, the utility's replacement strategy reflects the risk profile of its diverse asset base and accounts for changing asset demographics over time. Proactive replacement is appropriate where asset failures necessitate replacement to ensure public safety and to maintain system reliability. In contrast, where asset failures pose little or no impact to public safety, the environment or customer service, the relevant assets will be operated until failure and replaced reactively. The decision to run to failure also takes into account redundancy, contingencies and availability of spare units or components. For example, failure of distribution class transformers have low impact on system reliability; therefore, they are generally operated on a run-to-failure basis and replaced reactively upon failure. On the other hand, while certain distribution class transformers may continue to perform their intended function for a period of time, asset condition degradation (e.g., major corrosion, leaking oil) may be severe enough to warrant planned replacement to prevent environmental or safety impact. As another example, where a pole is found with major degradation and poses a material risk to the public, it will be addressed proactively to prevent the potentially serious public safety consequences of a pole failure. Table 5.3.3 - 2 summarizes Alectra Utilities' asset replacement strategies for various asset classes.

Table 5.3.3 - 2: Summary of Distribution Asset Replacement Strategies with the 2020 to 2024 DSP Period

Asset Class	Primary Replacement Strategy	Comments
Distribution class pad mount, pole mount and vault mount transformers	Reactive	Alectra Utilities normally manages its distribution class transformer population on a run-to-failure basis and reactively replaces units when they fail. However, Alectra Utilities prioritizes units for planned replacement where they pose risk to public safety or the environment (e.g. potential PCB contamination in the event of oil leak).
Pad Mounted Switchgear	Planned	Alectra Utilities targets a specific population of 27.6 kV air insulated switchgear for planned replacement due to a known risk of flash-over events leading to unit failure. In addition, Alectra Utilities will replace oil insulated switchgear that poses risks to safety and/or the environment (e.g. potential PCB contamination in the event of oil leak). See section 5.3.3.2 A.2 Pad Mounted Switchgear Replacement.
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 either in conjunction with line rebuild investments or on a reactive basis.

Asset Class	Primary Replacement Strategy	Comments
Wood and Concrete Poles	Planned	Alectra Utilities' strategy for pole replacement is driven primarily by pole condition demographics and replacement needs associated with legacy devices supported by poles. Prioritization of pole replacements is based on condition and criticality, in compliance with CSA requirements.
Underground conductors and accessories - primary Cross-linked polyethylene ("XLPE") cables	Planned	Alectra Utilities implements two types of strategies in managing its XLPE cable population: (i) cables which are beyond end of useful life (i.e. 35 years) will undergo planned replacements; and (ii) cables which are less than 35 years of age will be considered for cable rehabilitation. In the event that a cable fails while in service, Alectra Utilities will repair the cable by splicing out the faulted segment.
Underground conductors and accessories – primary paper insulated, lead covered ("PILC") cables	Reactive	Alectra Utilities currently replaces PILC cables reactively due to low historical failure rates and minimal customer outage impact. In the event of failure, PILC cables will be removed and replaced with ethylene propylene rubber-insulated ("EPR") cables. Alectra Utilities expects to shift to planned replacement of PILC with XLPE cables when a significant proportion of the PILC population ages past useful life.
Underground conductors and accessories - low voltage cables	Reactive	Alectra Utilities does not undertake planned replacement of underground secondary and service cables at this time, given their relatively low reliability impact in the event of failure. Instead, these assets are replaced reactively upon failure.

Asset Class	Primary Replacement Strategy	Comments
Substation Transformers	Planned	Alectra Utilities plans its power transformer replacements based on HI assessment (i.e., based on oil quality, dissolved gas analysis, other condition-related information) and with regard to input from stations SMEs as well as integrated planning considerations.
Substation Circuit Breakers	Planned	Alectra Utilities plans its circuit breaker replacements based on HI assessment, incorporating condition-based information and with regard to input from stations SMEs as well as integrated planning considerations.
Substation Switchgear	Planned	Alectra Utilities plans its switchgear replacements based on HI assessment, incorporating condition-based information and with regard to input from stations SMEs as well as integrated planning considerations.
Overhead low voltage Conductors	Reactive	Alectra Utilities does not undertake planned replacement of overhead main line secondary or service lateral conductors, given their relatively low reliability impact in the event of failure. Instead, these conductors may be replaced as part of other planned projects such as voltage conversions or pole line relocations.
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 regular inspections). If material asset degradation is identified, Alectra Utilities will execute refurbishment or replacement depending on the extent of the deterioration. Chambers that collapse while in-service are replaced or refurbished reactively.

Asset Class	Primary Replacement Strategy	Comments
Submersible Load Break Devices ("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. vac-pac units) will be targeted for planned replacement.
Overhead Line Switches	Proactive	Alectra Utilities manages replacement of overhead line switches through proactive and reactive replacement. Switches will be replaced in a planned manner based on HI. In some cases switches located within the scope of overhead line rebuilds may be replaced. The utility has initiated a maintenance program involving the cleaning and replacement of components that will prolong the life of overhead switches.

A Planned Asset Replacement

Through planned asset replacement strategies, Alectra Utilities aims to mitigate the risk of asset failure where such risk entails significant impact in terms of public or employee safety, financial cost, system reliability, customer service interruption, environmental impact, and/or 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. Furthermore, planned replacement is appropriate where large volumes of assets are approaching end of life (i.e. when an asset no longer performs its intended function in a reliable and economical manner or becomes functionally obsolete). In this regard, Alectra Utilities uses condition data and failure rates for an asset class to establish long-term failure projections. These projections are one of the factors used to determine asset renewal quantities and the pace of investment required to sustain the particular asset class at issue. This determination is a key part of Alectra Utilities' overall asset lifecycle risk management practices.

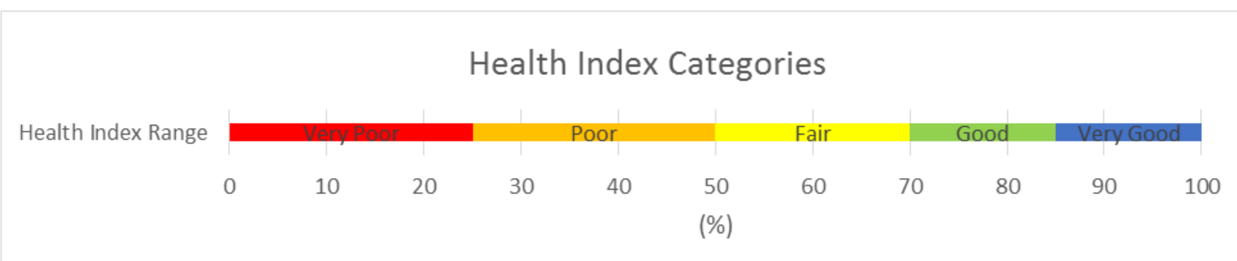
Planned asset replacements are organized into initiatives and portfolios of investments, which are paced to optimize resource allocation, minimize customer outages, minimize the need for reactive capital work, avoid sudden increases in renewal investment (and potential rate shock), and accommodate major procurement efforts.

Alectra Utilities identifies the need for planned asset replacement in the longer term (i.e., two years or more) through the ACA process. It identifies the need for short term asset replacement through ongoing maintenance and inspection activities, which help flag assets that are in a deteriorated condition and in need of replacement within the next year (i.e., to maintain reliable asset performance, mitigate public safety hazards, and minimize risk of environmental contamination).

As part of Alectra Utilities' overall asset management process, the ACA provides outputs regarding asset condition (i.e., HI scores) that, together with a range of asset needs drivers, inform the utility's strategic plans for sustainment and renewal investments.[52]

Alectra Utilities conducts ACA to derive HI scores for each major asset class, which are calculated using analytical models based on weighted inputs that quantify the condition of an asset in a consistent manner. The result is an indication of the asset condition of each major asset demographic across the HI spectrum from "Very Poor" to "Very Good", as illustrated in Figure 5.3.3 - 3 below.

Figure 5.3.3 - 3: Health Index Categories



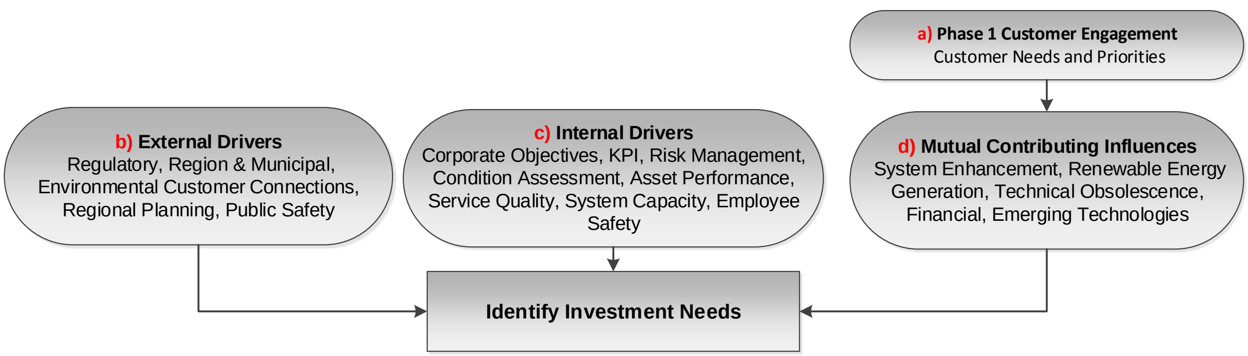
When identifying renewal investment needs, Alectra Utilities targets deteriorated assets (i.e., those assets in Very Poor and Poor condition) and develops an investment plan for each major

52 "Sustainment" is considered a form of renewal where options exist other than replacement (e.g. reinforcing a deteriorated wood pole) other than outright replacement of an asset.

asset class over the five year DSP planning period. In addition, Alectra Utilities assesses the asset class failure rates over a fifteen year horizon beyond the DSP planning period to project the impact of replacement rates on future asset demographics.[53] This process enables Alectra Utilities to more effectively manage investment renewal pacing in subsequent DSP planning periods, so as to minimize significant fluctuations in investment needs, avoid sudden rate impacts on customers, and ensure optimal resource planning. Having a long-term view of asset demographics allows the company to more effectively optimize the value of planned capital investments according to projected asset needs.

While the ACA is a key internal driver for purposes of Alectra Utilities' asset management process, a myriad of other internal and external drivers inform the identification of investment needs, as shown in Figure 5.3.3 - 4 below and discussed in Section 5.3.1.

Figure 5.3.3 - 4: Asset Management Process Investment Drivers and Considerations

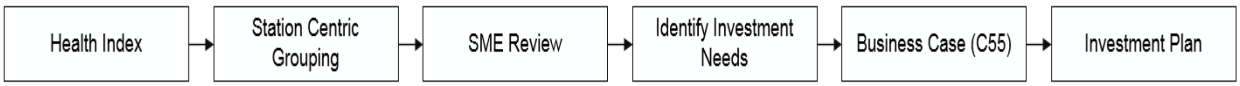


SMEs evaluate distribution asset ACA results to determine system renewal needs. This forms the basis for identifying technical solutions and developing business cases for proposed investments to address the assets requiring attention in alignment with ACA results (as well as other relevant drivers). Business cases are documented in the CopperLeaf C55 software system. Figure 5.3.3 - 5 and Figure 5.3.3 - 6 below illustrate the processes of identifying investment needs for distribution and station assets, respectively.

[53] These twenty year asset failure rates were calculated using the Typical Useful Life and Maximum Useful Life as provided in the "Asset Depreciation Study for the Ontario Energy Board" prepared by Kinectrics Inc., Report No: K-418033-RA-001-R000 (July 8, 2010).

Figure 5.3.3 - 5: Distribution Assets Condition Assessment

Figure 5.3.3 - 6: Station Assets Condition Assessment



CopperLeaf C55 is an important tool that 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 C55 anchors a uniform approach to Alectra Utilities' analysis and verification of a large number of capital projects with a significant annual spend across all operating zones. More specifically, it allows a myriad of scenarios spanning multiple years to be modeled, so as to inform the development of an optimal capital portfolio that balances financial and resource constraints as well as investment benefits and risks in alignment with Corporate Strategic Goals and Objectives (as discussed in section 5.3.1).

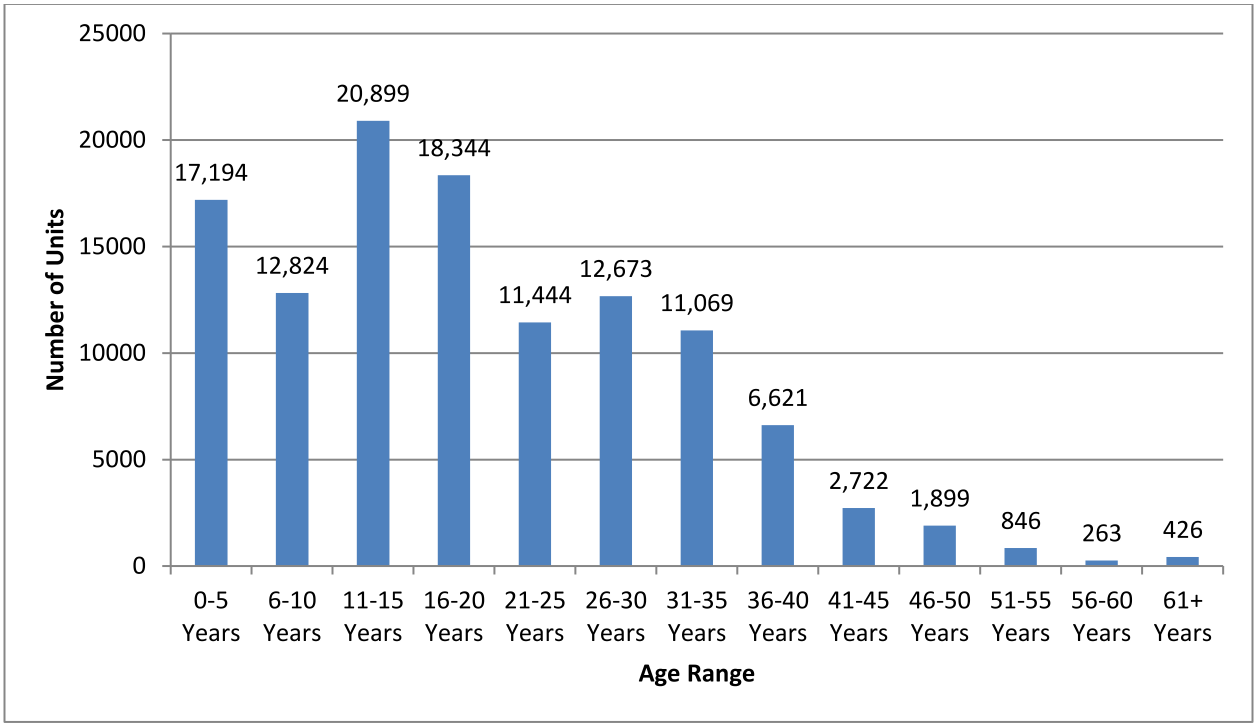
The CopperLeaf C55 application also provides a single repository for all capital investment information which can be updated to reflect new information.

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, criteria and HI values for each asset type. These approaches are explained further in this section.

A.1 Distribution Transformer Replacement

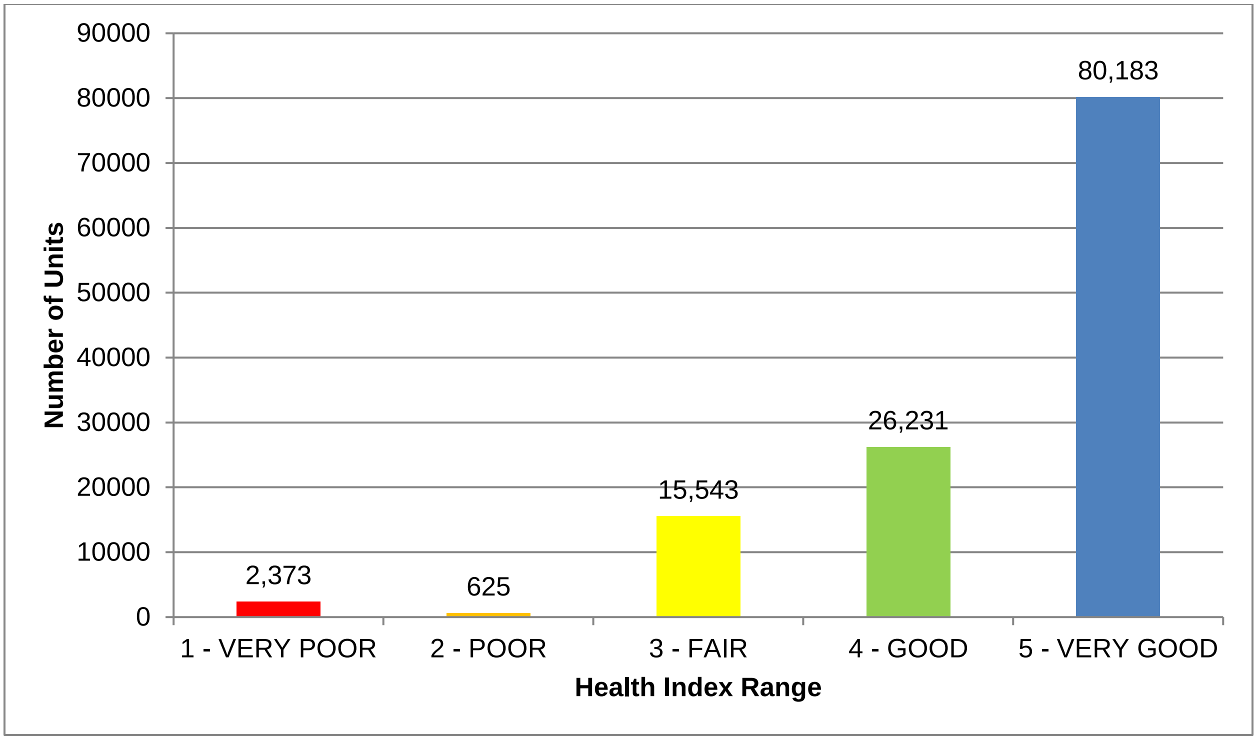
Alectra Utilities' in-service population of distribution class transformers totals 124,955 units. A breakdown of the age demographics is provided in Figure 5.3.3 - 7. Distribution transformers are vital to the provision of electrical service to Alectra Utilities' customers, providing the end users with utilization voltages from the primary distribution system. These transformers may be padmounted, pole-mounted or submersible, and are configured as single-phase or three-phase depending on the customer and type of load. Padmount transformers in the distribution system range from single phase 50 kVA units typically supplying residential customers to three phase 3,000 kVA units supplying industrial customers. All three types of transformers are filled with mineral insulating oil and employ sealed tank construction.

Figure 5.3.3 - 7: Age Distribution of All Distribution Class Transformers



Alectra Utilities' asset management strategy for distribution class transformers generally follows a run-to-failure approach, given that their failures pose relatively low impact on public safety, the environment and customer service. However, the company will pursue planned replacement if, in the course of inspections and normal operating activities, a transformer is found in a deteriorated condition (i.e., a "Poor" or "Very Poor" HI score) that poses risk to public or employee safety (e.g. corroded or damaged physical structure and compromised enclosure of energized components), risk of environmental contamination (e.g. containing PCB or showing signs of leaking oil), or identified to be overloaded. As shown in Figure 5.3.3 - 8, 2,998 transformers have been assessed with a "Poor" or "Very Poor" HI score, which means they exhibit major degradation and give rise to material environmental and/or safety risks. As such, they are proposed for replacement within the DSP period.

Figure 5.3.3 - 8: Health Index Distribution for All Distribution Class Transformers



Alectra Utilities also carries out planned replacements of transformers that are frequently subjected to loading beyond their nominal rating. In this regard, the company regularly performs transformer loading analysis to identify 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 located in a difficult to reach location, 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 transformers of a unique design that is no longer supported by standard inventories, then those transformers will be evaluated for planned replacement.

For larger three phase distribution transformers supplying commercial or industrial customers, the reliability impacts of transformer failures could be significant. These transformers may be replaced as they approach end-of-life or where frequent overloading is identified. In the latter case, the replacement transformer would be sized according to relevant loading requirements. Together, these replacement practices help minimize the impacts of transformer failures on Alectra Utilities' customers.

A.2 Pad Mounted Switchgear Replacement

Alectra Utilities' distribution class padmounted switchgear units 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 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/industrial customers via fused connections to main feeder cable systems.

Alectra Utilities' in-service fleet of padmounted switchgear totals 3,389 units, which include a combination of older models of air insulated units, oil insulated units, and SF6 insulated units, as well as newer technology solid dielectric units. These units may be manually operated, motor operated on-site, or in some cases remotely operable via SCADA. Figure 5.3.3 - 9 illustrates the age distribution of Alectra Utilities' switchgear fleet.

Figure 5.3.3 - 9: Age Demographics for all Switchgear

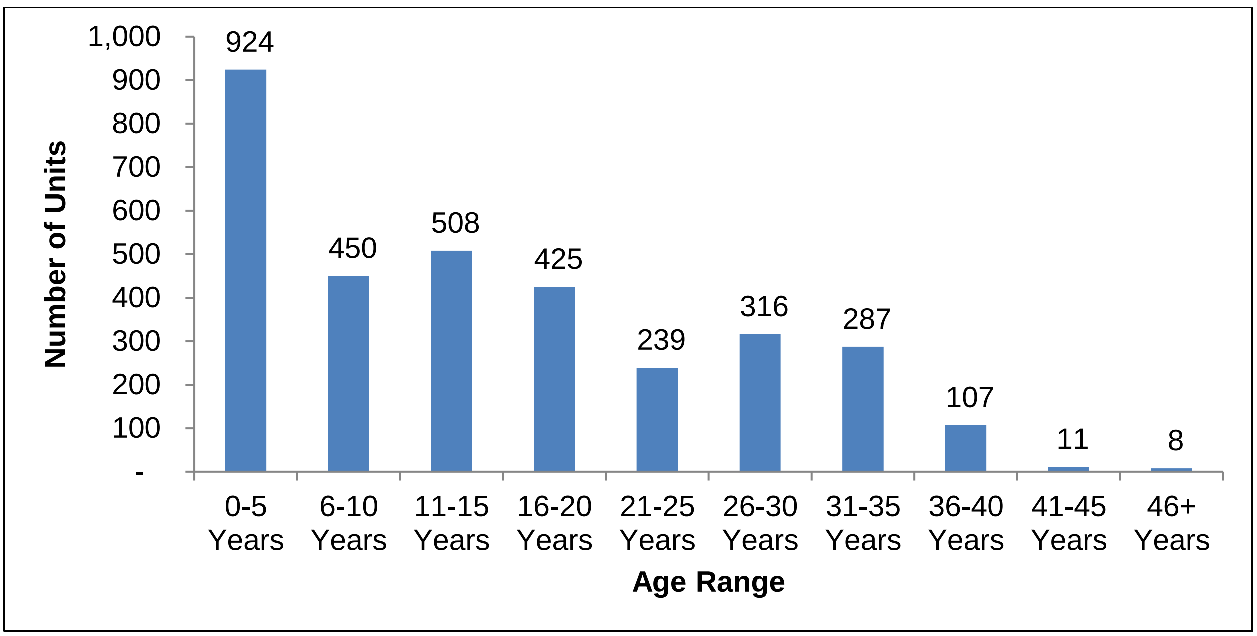
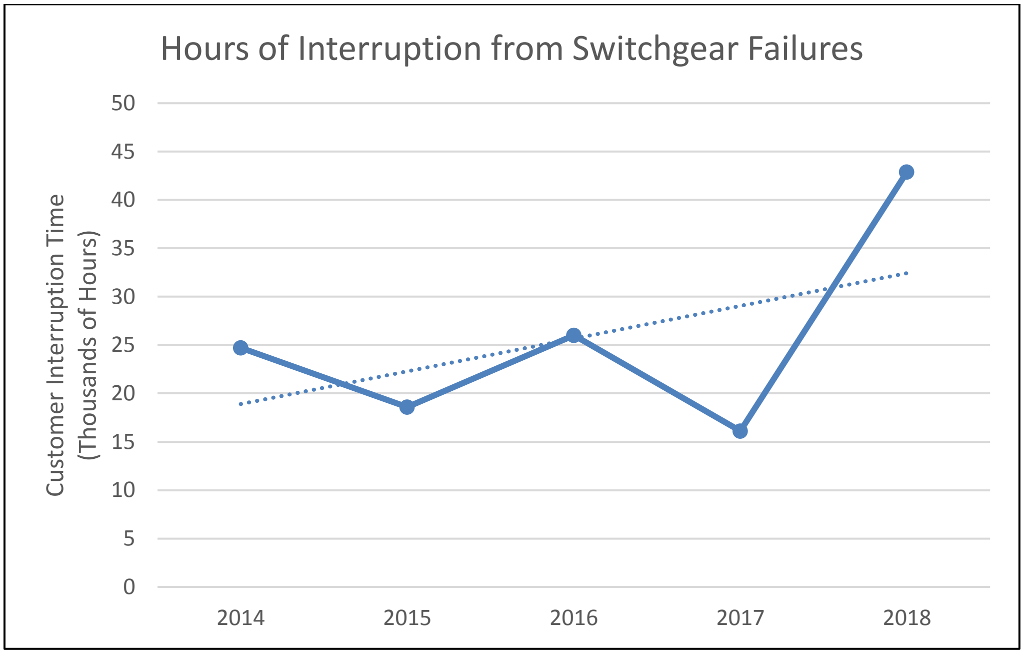


Figure 5.3.3 - 10 below shows the customer hours of interruption over the past five years due to switchgear failures. Over the past five years, Alectra Utilities has replaced about 80 switchgear units per year. However, there has been an overall increasing trend of customer interruption

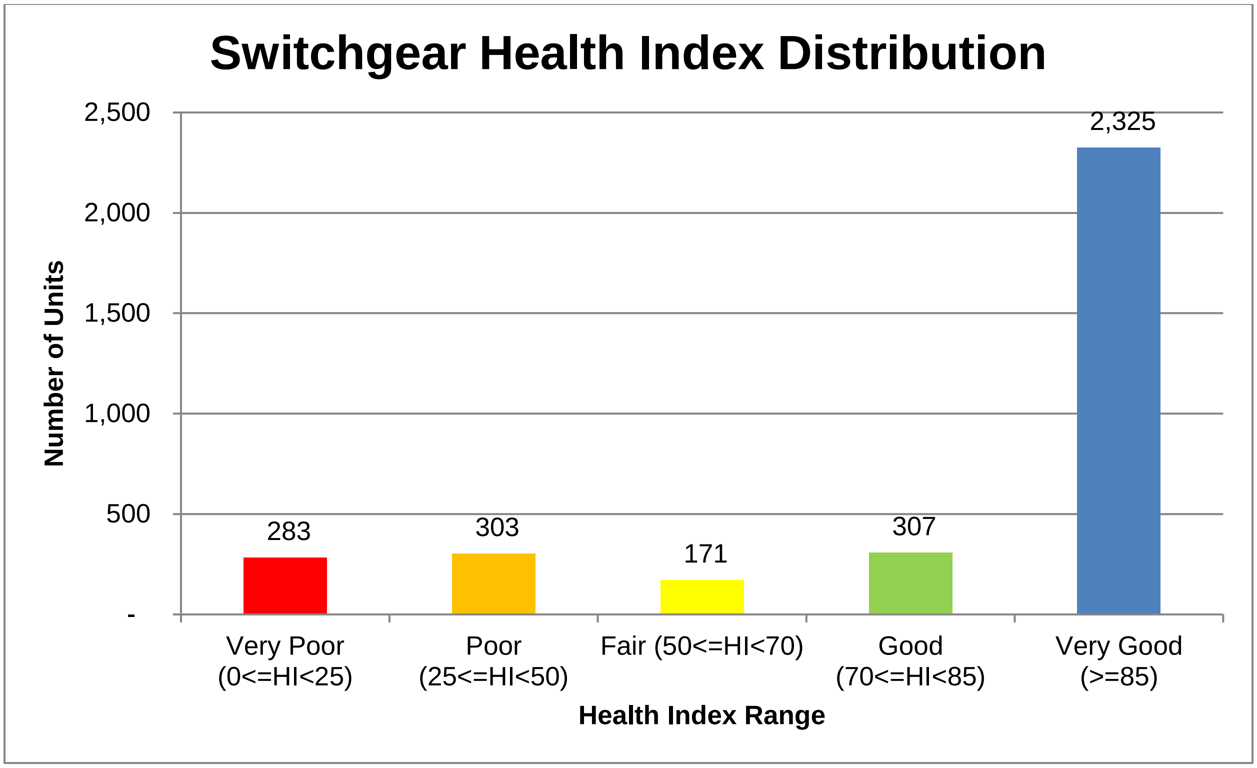
hours, which suggests that the recent rate of replacement is not sufficient to maintain stable customer outage levels associated with switchgear failures. These units continue to deteriorate over time and have been negatively impacting customer reliability.

Figure 5.3.3 - 10: Customer Hours of Interruption from Switchgear Failures (2014-2018)



Switchgear degradation depends on a number of factors, such as condition of mechanical components, contamination, moisture and corrosion. Through the ACA, Alectra Utilities derives the HI scores of switchgear units based on specific forms of degradation, which are a major (but not the only) input for purposes of calculating HI scores. In this regard, the HI models for switchgear incorporate weighted degradation factors specific to the different types of in-service switchgear. The HI distribution for Alectra Utilities' padmounted switchgear fleet is shown in Figure 5.3.3 - 11 below.

Figure 5.3.3 - 11: Condition Demographics for Switchgear



Alectra Utilities has identified two groups of legacy switchgear (25 kV air-insulated "live front" switchgear, and oil-insulated switchgear) that pose significant reliability and safety risks due to their condition, design and installation practices, as explained below:

- 25 kV air-insulated "live front" switchgear. The useful life of padmounted switchgear ranges from 20 to 45 years with a typical useful life of 30 years.[54] However, when installed on the 27.6 kV distribution system (as they are in parts of Alectra Utilities' underground distribution system), these units have failed at service ages as low as 11 years. The nominal voltage rating of these switchgear contributes to their reduced life span and adversely impacts their ability to perform under abnormal conditions, leading to premature failures. Environmental factors in southern Ontario have also led to earlier than expected failures of these switchgear. While these units function relatively well in dry conditions, southern Ontario's environment presents many challenges that cause units to fail. In

[54] Based on the "Asset Depreciation Study for the Ontario Energy Board, Kinectrics Inc. Report No: K-418033-RA-001-R000 July 8, 2010".

particular, high humidity, condensation from changing temperatures, and water in the below-grade foundations when mixed with dirt and road dust all contribute to the formation of conductive paths on the insulating components. Over time, these factors ultimately reduce the switchgear's insulating properties and lead to flashover and unit failure.

- <u>Oil-insulated Switchgear</u>. Alectra Utilities also has a significant population of 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 a public and worker safety hazard. 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 contamination, and resulting site remediation, may also be potential consequences.

Alectra Utilities' replacement strategy to address its population of deteriorating padmounted switchgear focuses on four key aspects:

- Safety and environmental risk: Units that pose safety risk (e.g., exposed energized parts, risk of fire) or environment risk due to oil leaks (i.e., specific to oil insulated units noted above) warrant the highest priority for replacement.
- Asset condition: Units that are in "Very Poor" or "Poor" condition will be prioritized from the lowest (i.e., the worst) to highest HI scores.
- Project coordination: When switchgear units warrant replacement based on condition, those 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. This strategy facilitates the optimal allocation of financial and logistical resources.

Based on the above areas of focus, Alectra Utilities' switchgear replacement strategy includes the elimination of existing 27.6 kV air-insulated switchgear and oil-insulated switchgear of all voltage ratings in coordination with system rebuild projects, where feasible. Alternatively, where coordinated execution as part of existing projects is not available, Alectra Utilities will proceed with a replacement strategy based on the system operating voltage, as explained below.

For switchgear operating at 27.6 kV, air-insulated units will be replaced with standard 38 kV rated solid dielectric units, thereby eliminating the risks associated with contamination and resulting tracking and flashover events.

For switchgear operating at 15 kV or lower, Alectra Utilities will utilize 27.6 kV rated air-insulated units for replacements, which are expected to perform reliably when operated at 15 kV or lower.

Switchgear investment pacing options are discussed in Appendix A10 - Underground Asset Renewal.

A.3 Overhead Primary Conductors

Alectra Utilities' overhead distribution system is comprised of conductors of many different 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 conductors involved are vintage #6 or smaller, which typically remain in-service from older, lower voltage primary systems (e.g., 4.16 kV and 8.32 kV) 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 particular 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. In 2017, one such conductor failed and fell to the ground during a severe weather event, resulting in a fatality.

Undersized primary conductors (i.e., #6 or smaller) represent a significant risk to the public and Alectra Utilities' crews. As such, Alectra Utilities' strategy is to perform planned conductor replacements. The majority of undersized conductor replacements will be carried out in conjunction with planned conversions of vintage 4.16 kV and 8.32 kV systems, which contain the majority 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. See Appendix A, Investment Summary A15 - Safety and Security

A.4 Poles

Wood and concrete poles support Alectra Utilities' overhead distribution plant and are critical to the delivery of electricity to customers. The utility's overhead distribution system includes 130,909 poles (105,569 wood poles and 25,340 concrete poles)**.** Pole age demographics for wood and concrete poles are illustrated in Figure 5.3.3 - 12 and Figure 5.3.3 - 13, respectively.

Figure 5.3.3 - 12: Wood Poles Age Distribution

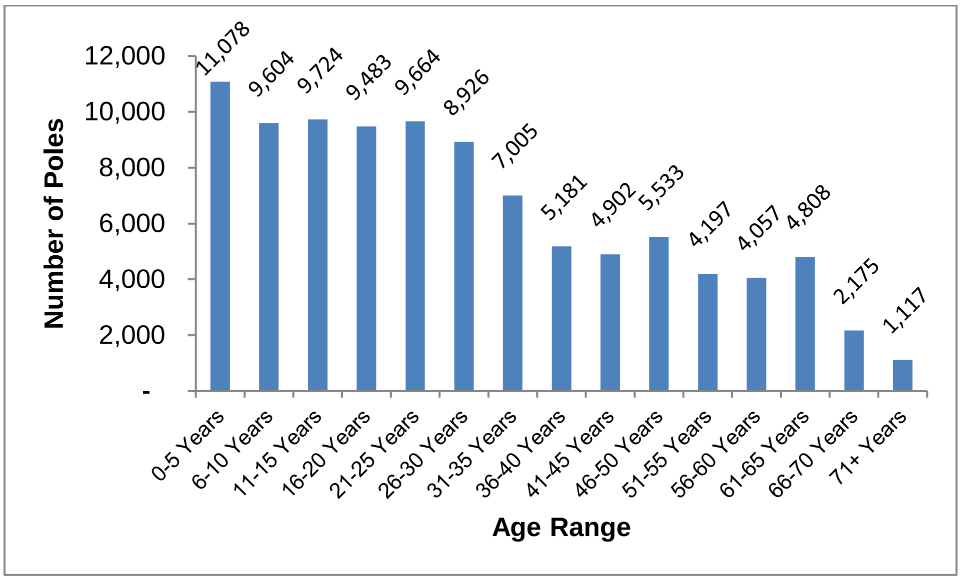
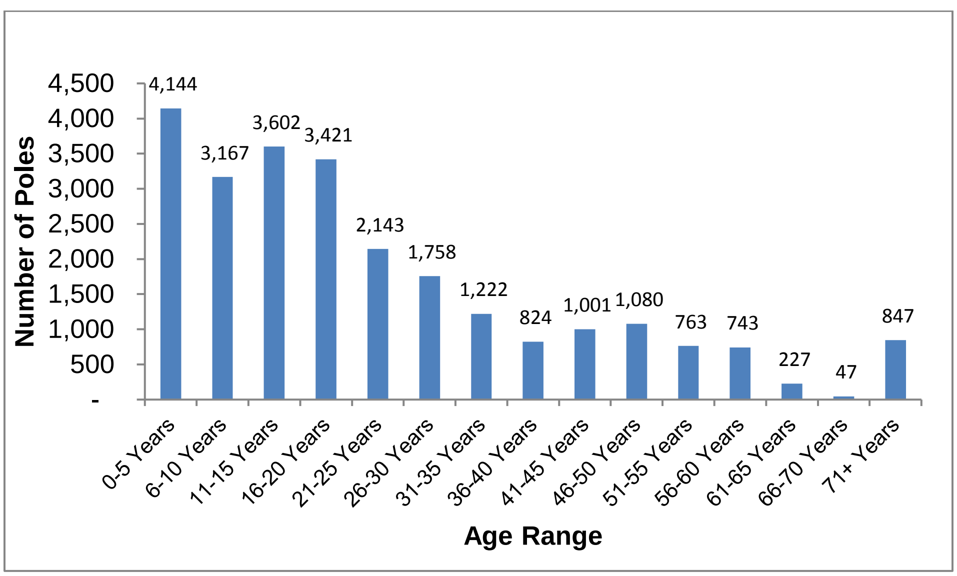


Figure 5.3.3 - 13: Concrete Poles Age Distribution



Alectra Utilities' planned pole replacement and refurbishment investments include Pole Sustainment and Storm Hardening (Please see Appendix A05 – Overhead Asset Renewal). Pole Sustainment involves the remediation of deteriorated wood and concrete poles that are in Poor or Very Poor condition as determined through the ACA. Alectra Utilities will consider reinforcing poles where practicable. However, poles that have deteriorated significantly will warrant replacement, as well as poles that:

- are located in critical locations (e.g., highways, in proximity to railways, river crossings, circuit dead-ends, and line angles);
- support transformers, switches, or telecommunication equipment;
- are in poor condition such that reinforcement will not remediate safety hazards or slow the deterioration process (e.g. upper part of wood pole is in poor condition, or significant deterioration of rebar in concrete pole).

Through the Storm Hardening investment, Alectra Utilities will replace wood poles that are likely to experience catastrophic failures under adverse weather conditions. These investments are further described below.

A.4.1 Pole Sustainment Investments

Pole Sustainment investments are primarily driven by HI results from the ACA process. Through annual pole inspection and testing programs, Alectra Utilities assesses and monitors the condition of its pole population, to ensure they remain in safe and serviceable while meeting applicable safety and reliability requirements. Through these programs, Alectra Utilities collects data relating to certain pre-defined condition attributes, which help determine pole condition and establish HI scores for pole assets. These condition attributes are captured from pole testing (applicable to wood poles) or visual inspections (applicable to wood and concrete poles).

Alectra Utilities' selection and prioritization of pole replacement candidates begin with the identification of deteriorated poles (i.e. those in Very Poor or Poor condition, as determined through the ACA). Pole HI is condition based, and computed based on specific forms of degradation identified through inspections and pole testing. Remaining pole strength test results and visual indicators of condition (e.g., rot, decay, splitting, insect infestation, bending, and leaning) factor into the HI models, which provide a means to differentiate asset condition across the entire pole population. Once the utility identifies poles in the Very Poor and Poor condition for further action, it prioritizes poles for replacement or reinforcement starting with poles having the lowest HI scores.

Condition attributes are weighted in order to derive the HI score. Figure 5.3.3 - 14 illustrates the HI distribution of wood poles. Approximately 9% of Alectra Utilities' wood poles are in Poor or Very Poor condition. Figure 5.3.3 - 15 illustrates the HI distribution of the concrete poles. Approximately 5% of Alectra Utilities' concrete poles are in Poor or Very Poor condition.

Figure 5.3.3 - 14: Wood Pole Health Index Demographics

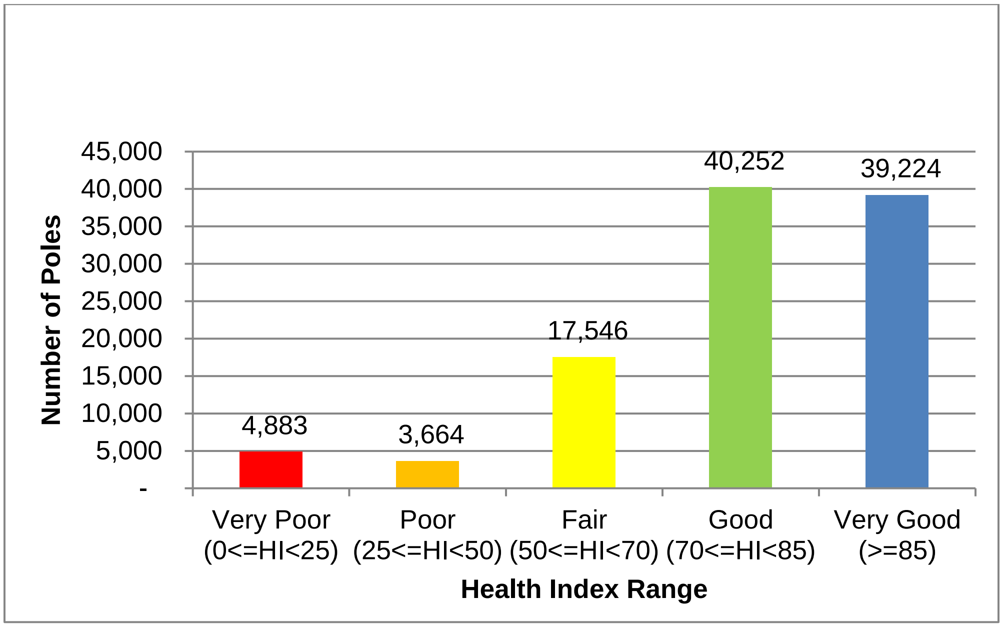
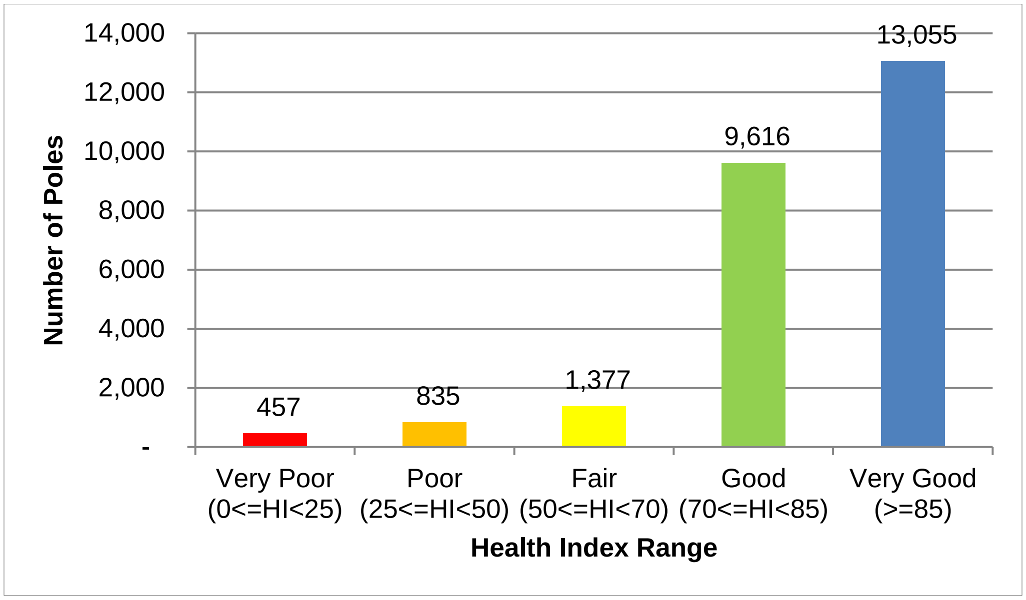


Figure 5.3.3 - 15: Concrete Pole Health Index Demographics



During the inspection process, crews assess various aspects of a pole's condition. Key degradation indicators for wood poles include:

- Remaining pole strength;
- 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:

- Rusting/corrosion of the re-bars;
- Concrete spalling; and
- Mechanical damage.

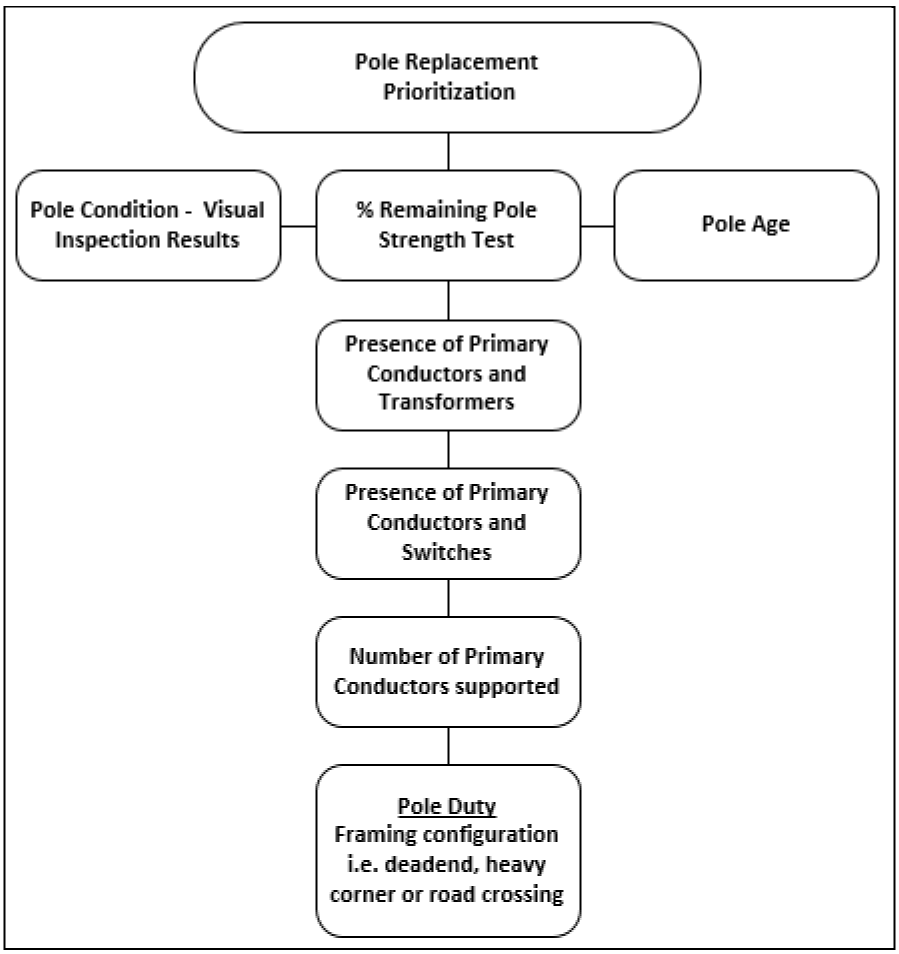
Alectra Utilities plans to replace poles in Very Poor and Poor condition with concrete or wood poles that conform to current standards. In this regard, the utility adopts industry standards from the Canadian Standards Association ("CSA") regarding overhead construction, namely CSA Standard C22.3 No. 1-10[55], which states: "When the strength of a wood pole structure has deteriorated to 60% of the required design capacity, the structure shall be reinforced or replaced".

[55] Canadian Standards Association, CSA C22.3 No. 1-10 "Overhead Systems", section 8.3.1.3.

Alectra Utilities' Pole Sustainment investments will support the utility's ongoing compliance with applicable requirements.

In prioritizing poles for replacement or reinforcement, the weight assigned to relevant criteria is shown in Figure 5.3.3 - 16 below.

Figure 5.3.3 - 16: Pole Replacement Prioritization Steps



The utilization of standardized metrics to score and rank pole investments allows Alectra Utilities to target the most critical needs and ensure objectivity and consistency in the decision-making process. Detailed discussions regarding the options analysis and pacing of the Pole Sustainment investment are provided in Section 2.4 of Appendix A05 – Overhead Asset Renewal.

A.4.2 Storm Hardening

Storm Hardening investments target a specific population of Alectra Utilities' wood poles that carry four circuits and are particularly susceptible to catastrophic failure during severe weather. While these poles have sufficient strength to support the load of the four circuits under normal operating conditions, storms and high wind events can result in high stress on these poles, leading to pole failure and potential catastrophic and cascading failure of multiple poles. The failure impacts of these poles are shown in photos found in Figure 5.3.3 - 17 to Figure 5.3.3 - 19 below.

Figure 5.3.3 - 17: Downed Overhead Line on Warden Avenue in Markham on June 17, 2014

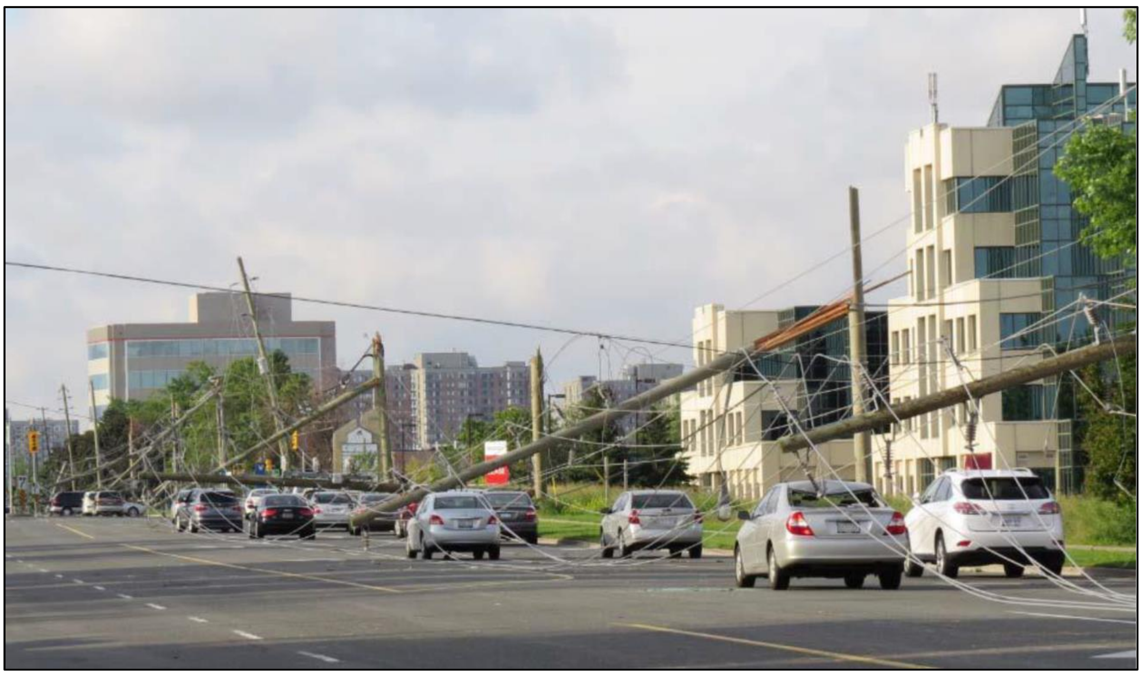


Figure 5.3.3 - 18: Failure of Legacy 4 cct Wood Pole on Warden Avenue in Markham on June 17, 2014

Figure 5.3.3 - 19: Failure of Legacy Wood Pole on Islington Avenue in Vaughan on October 15th, 2017

Alectra Utilities plans to replace these poles with standard concrete poles, which will provide sufficient structural load rating and comply with the CSA's ice and wind loading standards based on non-linear pole loading analysis. This strategy retains the existing four circuit configuration, which still carries the risk of four-feeder outages going forward if a concrete pole fails. However, this strategy will significantly mitigate the probability of pole failures, and is the most feasible and cost-effective option in terms of implementation (since it avoids the need for additional land rights to site a new line). This option also entails the most aesthetic value, with every pole being built to the same height and standard.

As shown in the above photos, failures of legacy wood poles carrying four circuits have resulted in serious safety impacts (in addition to service interruptions). Should any of the remaining legacy four-circuit wood poles in Alectra Utilities' service area collapse, it would result in similar hazards with all four feeders dropping to the ground, jeopardizing field crews as well as the general public.

Detailed discussions regarding the options analysis and pacing of the Storm Hardening investment is provided in Section 3.4 of Appendix A05 – Overhead Asset Renewal.

A.5 Automated, Manual and Mini-Rupter Switches

Alectra Utilities' distribution system includes 3,889 overhead switches of varying types and configuration. Figure 5.3.3 - 20 shows the age demographics of this switch population, and Figure 5.3.3 - 21 shows its HI distribution.

Figure 5.3.3 - 20: Overhead Switches Age Distribution

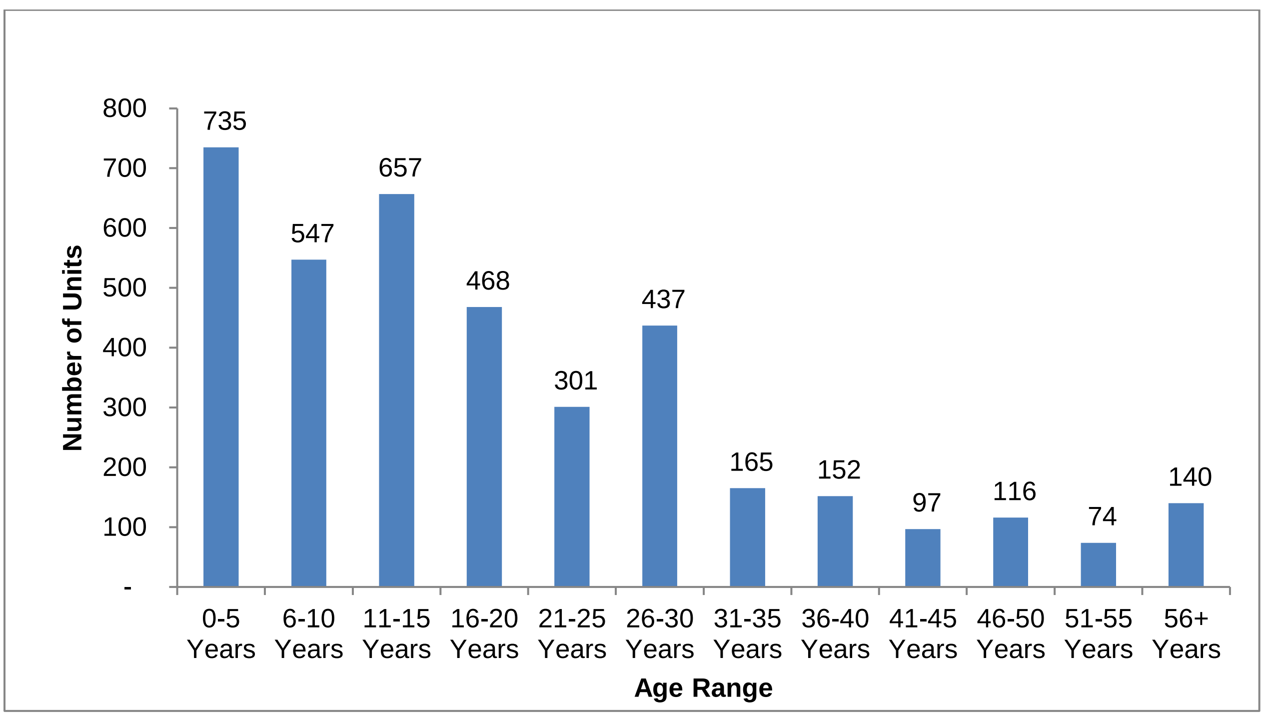
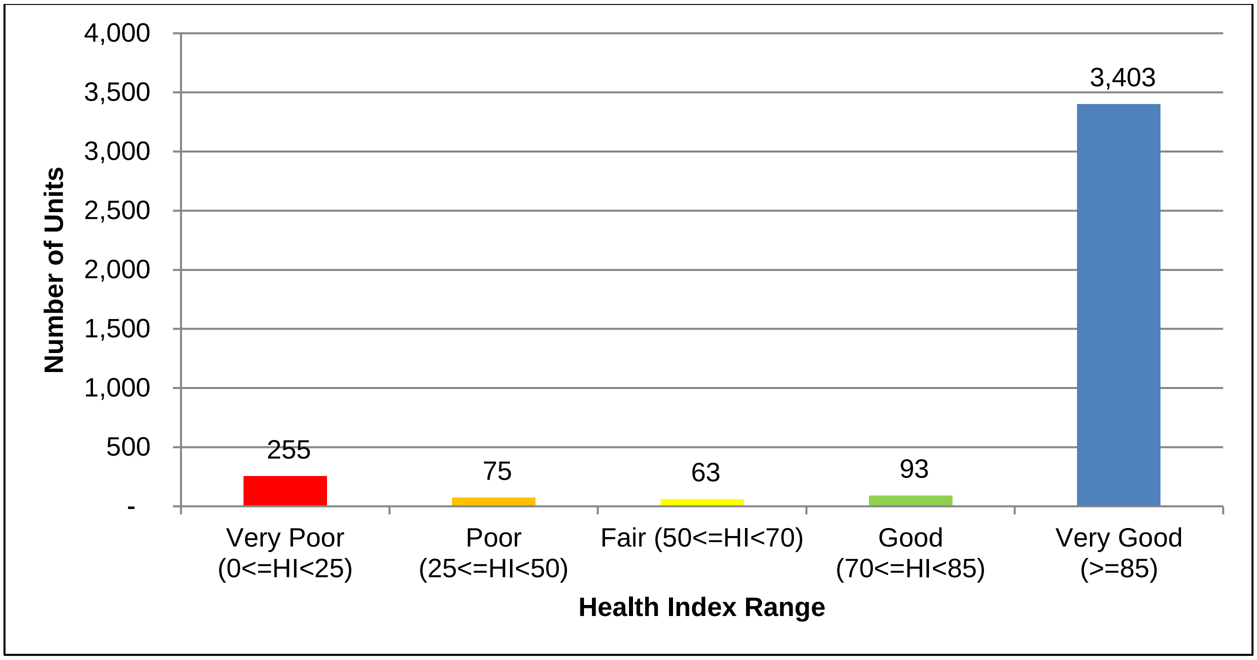


Figure 5.3.3 - 21: Overhead Switches Health Index Distribution



The main switch types in Alectra Utilities' distribution system include: (i) SF6 and solid dielectric insulated units with vacuum interrupters, (ii) air insulated load interrupter switches, and (iii) mini-rupter switches. The first two types (i) and (ii) are both referred to as Load Interrupting Switches ("LIS").

Alectra Utilities manages its fleet of overhead switching assets (i.e. the above-noted LIS units) based on a combination of ACA HI results and findings from switch inspection and maintenance. Alectra Utilities assesses all overhead LIS units in the Very Poor and Poor HI categories for further action, and prioritizes these switches for replacement starting with those having the lowest HI scores. Switch location and HI results, which are known for all LIS assets, support the determination of replacement candidates. The scope and volume of required replacement are driven by a number of considerations, including HI results, switch type, manufacturer and performance history. When evaluating replacement options and timing, Alectra Utilities considers other factors, such as the location of the switch in relation to line rebuild initiatives and road authority requests for line relocations.

As part of its switch replacements, Alectra Utilities evaluates if the switch is a candidate for automation. 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. In addition, 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 normal open point, in the event that 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.

Mini-rupter switches are legacy switching assets that are typically installed in vault rooms. First installed on the distribution system in the 1970s, mini-rupter switches now pose significant reliability and safety risks due to their deteriorated condition, lack of arc flash ratings, and vulnerability to contamination resulting in switch failure. At the time of installation, these units were one of very few economical solutions available for indoor switching; however, they no longer conform to present day standards (including CSA arc flash requirements). Alectra Utilities has experienced several failures of mini-rupter switches, with a number of failures resulting in arc flash events. The risk of injury is significantly elevated as these switches are located in confined vault rooms. To address this safety risk, Alectra Utilities has, through its standard work practices, restricted the switching of mini-rupter switches under energized conditions, which is contrary to the units' intended function. This practice improves worker safety but increases customer outage time and cost when the operation of these units is required.

Alectra Utilities manages its fleet of mini-rupter switching assets based on a combination of the ACA HI results and findings from switch inspection and maintenance. Alectra Utilities prioritizes these switches for replacement starting with those having the lowest HI scores and evaluating if any units are located within proposed cable remediation initiatives. Mini-rupter switches are commonly replaced in conjunction with cable remediation and cable replacement initiatives where opportunities exist to do so. Alectra Utilities replaces mini-rupter switches with padmounted switchgear units, following the same practice described above for pad mounted switchgear (Section 5.3.3.2, A.2 – Pad Mounted Switchgear Replacement).

Detailed discussions regarding the options Analysis and pacing of the switch replacement investment is provided in Appendix A05 - Overhead Asset Renewal.

A.6 Porcelain Insulators

A number of legacy pole lines in Alectra Utilities' service territory utilize legacy porcelain or first generation polymer insulators to support overhead primary conductors. Such insulators of certain vintages have experienced tracking, resulting in pole fires that caused poles to lose structural integrity and fall to the ground. Figure 5.3.3 - 22 and Figure 5.3.3 - 23 illustrate pole fires impacts caused by insulator tracking.

Alectra Utilities' strategy with respect to these legacy insulators is to pursue planned replacements either in conjunction with pole replacement projects or on a targeted basis if an existing pole supporting the insulators is in good condition. Alectra Utilities replaces the legacy insulators with current day standard polymer/silicone insulator units, with voltage ratings above the operating voltage of the system on which the insulators will be installed. Overhead insulators for use on 44 kV and 27.6 kV systems will be rated at 69 kV. Overhead insulators for use on 13.8 kV system voltages and below will be rated at 27.6 kV. The additional margin of protection offered by such insulator voltage ratings will improve system reliability by mitigating the potential for insulator tracking and resulting pole fires.

Figure 5.3.3 - 22: Active Pole Fire Event Alectra Utilities

Figure 5.3.3 - 23: Pole Fire Event Alectra Utilities

Detailed discussions regarding options analysis and pacing of the insulator replacement investment are provided in Appendix A05 – Overhead Asset Renewal.

A.7 Fault Indicators

Fault indicators are a crucial component of the distribution system in terms of locating faults, 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.

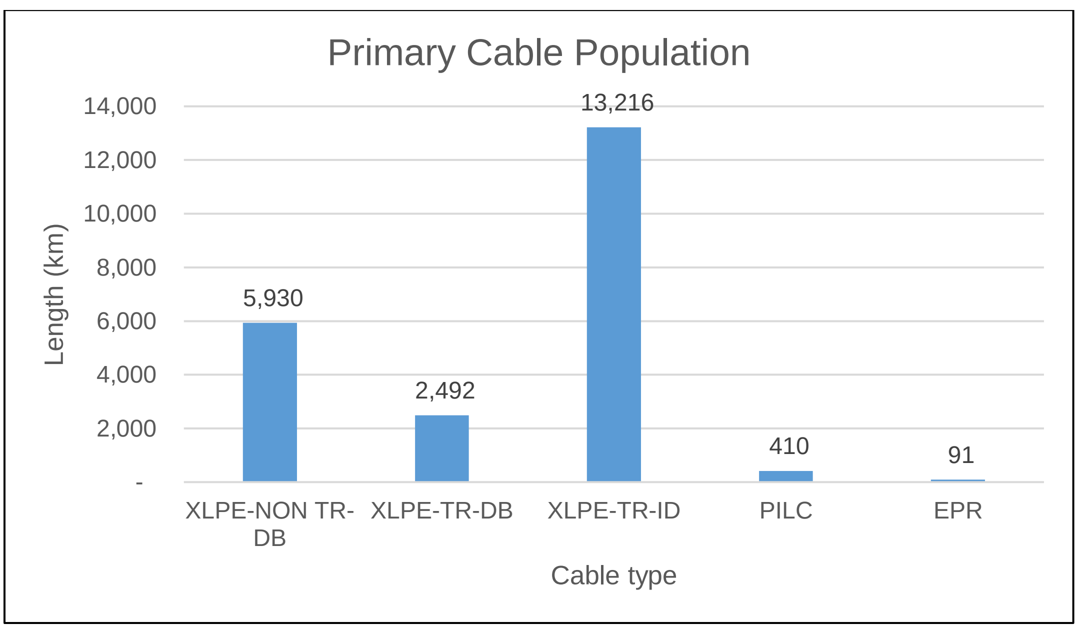
Alectra Utilities' distribution system includes various types of fault indicators, which were installed by Alectra Utilities' predecessor utilities pursuant to different practices in effect at the time. Some geographical areas of the service territory have a large number of fault indicators, while others have a smaller fleet or no fault indicators at all. Alectra Utilities plans to: (i) install new fault indicators in parts of the distribution system that currently contain none, and (ii) replace older fault indicators that are technologically obsolete and prone to malfunction.

A.8 Underground Conductor and Accessories

Alectra Utilities owns and operates over 22,000 cable km of underground primary cables of various types, namely: cross-linked polyethylene ("XLPE") cable, paper insulated lead covered ("PILC") cable, and ethylene propylene rubber-insulated ("EPR") cable. This cable population is critical to the delivery of localized electrical service as well as bulk power flows across the utility's service territory.

Figure 5.3.3 - 24 illustrates Alectra Utilities' cable population in linear cable kilometers by cable type and installation method. As illustrated, XLPE cables make up the vast majority (over 97%) of the utility's in-service primary cable population.

Figure 5.3.3 - 24: Primary Cable Population



In order to manage the life cycle of its primary cable population, Alectra Utilities utilizes cable performance statistics (e.g. failure rates and customer outage impacts) in conjunction with cable HI results to identify risk and accordingly plan cable renewal investments. In 2018, Alectra conducted an ACA for primary underground cables using HI models configured for each cable type. The resulting HI distributions are shown in Figure 5.3.3 - 25 to Figure 5.3.3 - 27.

Figure 5.3.3 - 25: Primary XLPE cables Health Index Distribution

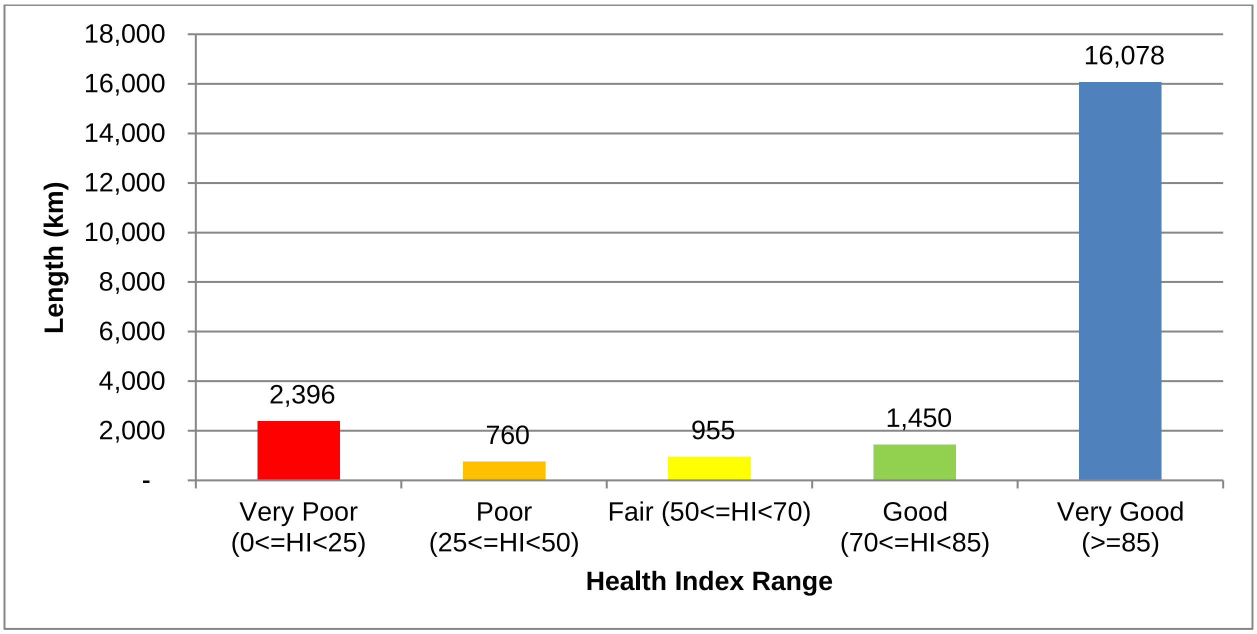


Figure 5.3.3 - 26: Primary PILC cables Health Index Distribution

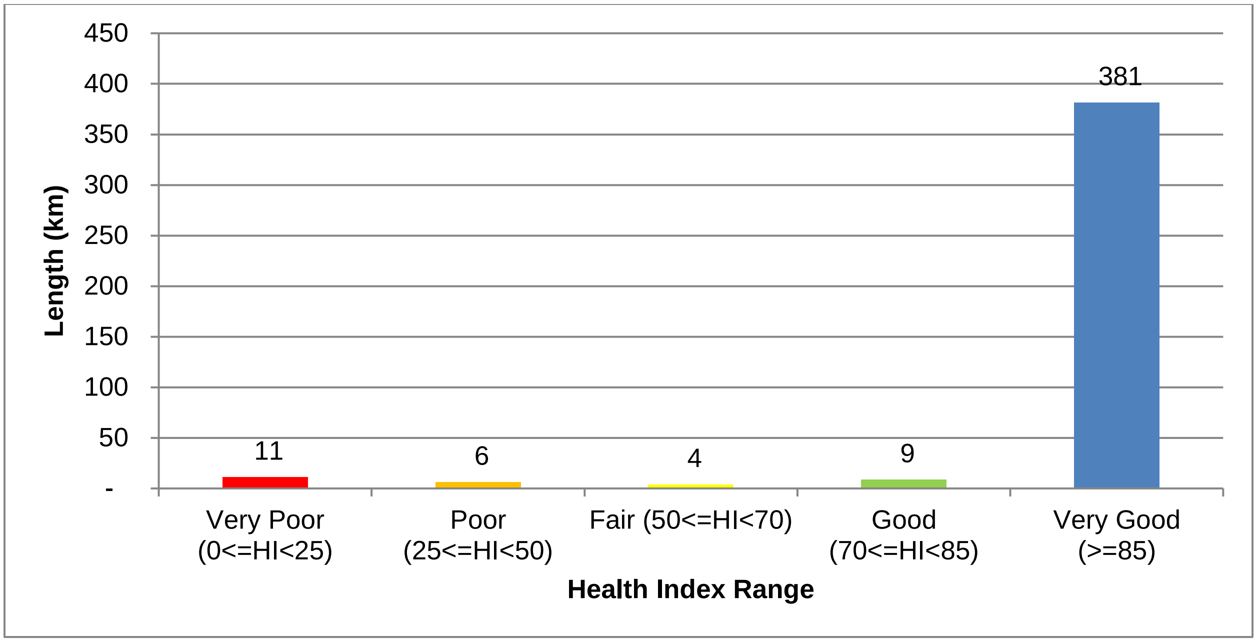
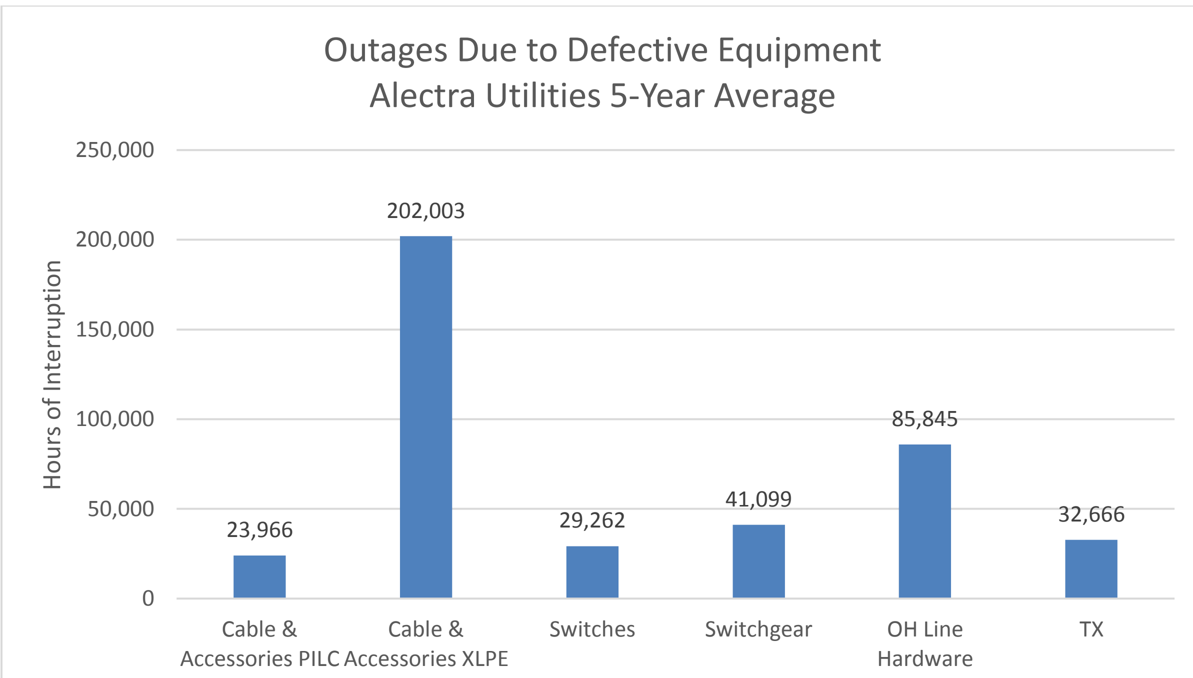


Figure 5.3.3 - 27: Primary EPR cables Health Index Distribution

A.8.1 XLPE Cable

As illustrated in Figure 5.3.3 - 25, Alectra Utilities' ACA identified 3,156 km of XLPE cables in the Very Poor and Poor condition. The HI results were an important input for the determination of cable failure risk. In addition, the utility compiles equipment failure statistics as shown in Figure 5.3.3 - 28, which illustrates the significance of XLPE cable and accessory failure rates on customer outages compared to all equipment-related failures.

Figure 5.3.3 - 28: Hours of Interruption form Equipment Failures



As illustrated above, failure of XLPE cable and accessories is the highest contributor to customer hours of interruption. This is a reflection of the volume and vintage of XLPE cable currently in service in Alectra Utilities' service area.

To develop mitigation strategies that manage the failure risk of primary XLPE cable, Alectra Utilities examined the history of the XLPE cable construction methods. Cable manufacturers introduced the first-generation XLPE cables, which were constructed with stranded or solid conductors, into the market in the late 1960s. These cables have inherent problems due to the technology and capability of the manufacturing processes available at the time for these cables, 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 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.

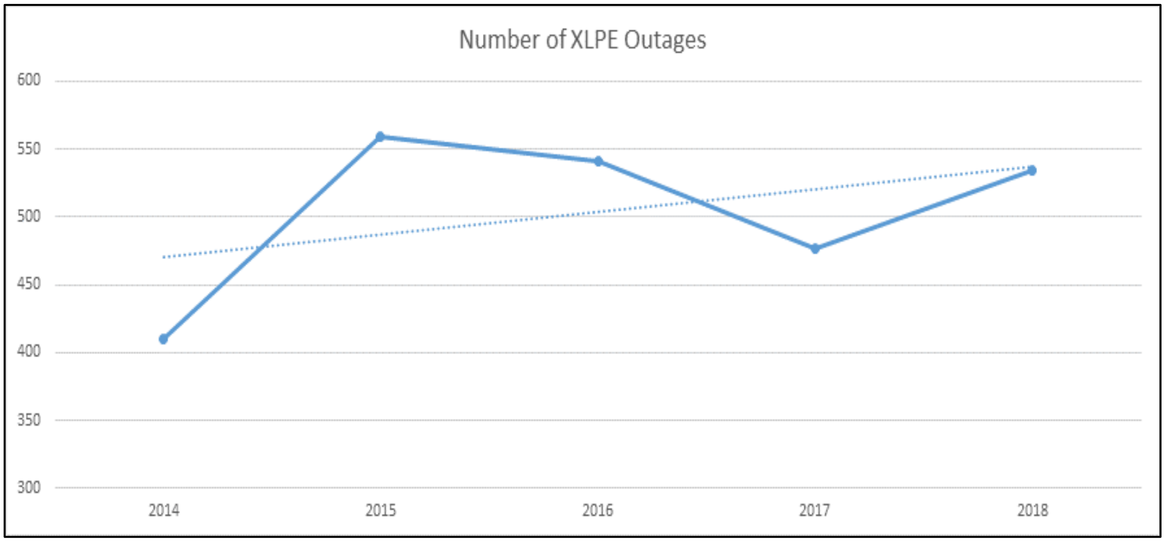
Compounding the issue is that these first generation cables were originally installed in excavated trenches on a direct-buried basis, with little or no separation between cables, and without any additional mechanical protection that would be offered by a ducted installation. For this reason, these cables 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. This challenge was particularly salient when repairs were required to replace faulty heat shrink splices experienced by several of Alectra Utilities' predecessor utilities, which caused significant reliability issues. Under this repair approach, the original cable would still remain in service.

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.

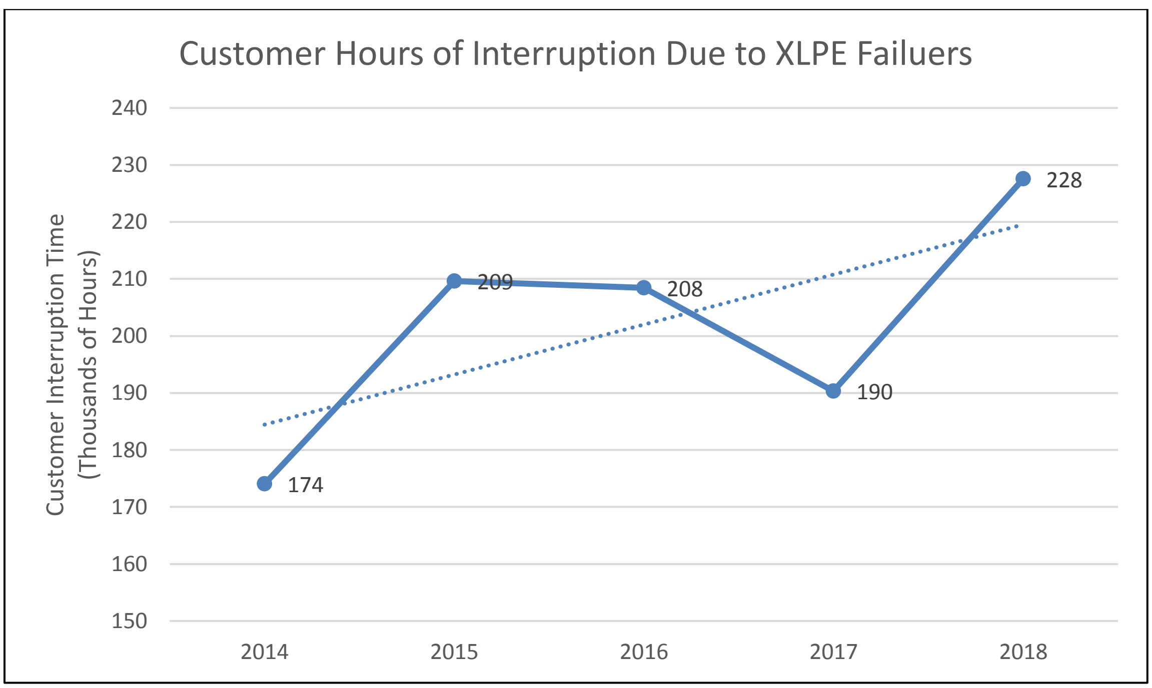
On average, Alectra Utilities experienced over 600 outages per year from 2014 to 2018 due to XLPE cable failures, which increased at an average rate of 6% over the period. The corresponding customer outage duration increased at an average rate of 8% per year since 2014. XLPE cable outage frequency is illustrated in Figure 5.3.3 - 29.

Figure 5.3.3 - 29: Number of Outages due to XLPE cable failure



These cable failures resulted in significant number of customer-hours of interruptions as shown in Figure 5.3.3 - 30.

Figure 5.3.3 - 30: Customer-Hours of Interruptions



Alectra Utilities has attempted to address the increasing failure trends associated with XLPE cable through its existing funding levels; however, as indicated by the increasing cable failure rates, past expenditures have not adequately enabled the company to maintain cable performance at acceptable levels. As shown in Figure 5.3.3 - 28 above, XLPE cables are the single largest equipment-related cause of outages in Alectra Utilities' distribution system. Failing direct-buried cables are causing an increasing number of outages, which result in prolonged restoration efforts and significantly impact the quality of service received by Alectra Utilities' customers. Managing the failure risk associated with its XLPE cable fleet is Alectra Utilities' most pressing investment need. To this end, during the 2020-2024 period, Alectra Utilities plans to gradually and significantly increase its spending to rehabilitate (i.e. by cable injection) or replace XLPE cables and related accessories that are either in Poor or Very Poor condition.[56]

A.8.2 PILC Cable

PILC represents a much smaller proportion of Alectra Utilities' primary cables. 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.

Alectra Utilities' current practice is to replace PILC cables reactively upon failure, and closely monitor PILC cable failure rates by segment locations. This is intended to identify PILC performance trends to inform future planned replacements for this cable type. When replacing PILC cables, 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 is not 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

[56] Underground assets targeted for renewal have Very Poor or Poor HI scores. Detailed information on Alectra Utilities' ACA process is provided in DSP Appendix D - Asset Condition Assessment - 2018

this approach is the availability 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).

A.8.3 EPR Cable

First introduced in the early 1960s, EPR cables are the smallest population of underground primary cables in Alectra Utilities' system. While costlier than XLPE, EPR insulation is recognized for its superior flexibility and smaller diameter than equivalent XLPE cable. Alectra Utilities' practice is to use EPR cables as replacement for failed PILC cables. Because of the smaller diameter, three EPR cables can be bundled together and fit within existing 3.5 inch ducts. Alectra Utilities' population of EPR cables are relatively new, with none exceeding 10 years in age. These cables are replaced reactively upon failure, with no planned replacements at this time. A renewal plan for PILC and EPR cable replacements beyond 2024 will be developed during this DSP period.

A.8.4 Primary Cable Renewal Strategy

In developing its cable renewal strategy, Alectra Utilities recognized that its cable population consists of different cable construction types, and accordingly explored different solutions to mitigate the impacts of failing cables. Alectra Utilities also recognized that as these cables continue to deteriorate, cable segments will move into lower HI categories (i.e., toward Poor and Very Poor HI scores), and give rise to increasing failure risks. As such, and for the reasons discussed above (particularly for XLPE cables), it is imperative that Alectra Utilities address the current fleet of cables in Very Poor and Poor condition.

Alectra Utilities' renewal strategy includes cable replacement and cable injection investments. Where feasible, the utility pursues 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, which can be both costly and disruptive for customers.

Alectra Utilities considers the following factors in deciding whether to pursue cable injection or cable replacement in each case:

- Location of splices and proximity to each other. Splices located beneath landscaped and hard surface areas may be costly to excavate and restore for purposes of cable injection, which would render replacement more economically feasible.

- Number of splices within the segment. If a given cable segment has multiple splices, replacement may be more economically feasible than excavating and replacing each splice.
- Location of cable (e.g. under a boulevard, under a sidewalk, under a roadway, under a driveway). Cables located beneath landscaped and hard surface areas may be costly to excavate and replace. In this case, cable injection may be more economically feasible.
- Cable condition. Cable segments that have been tested and identified to be in poor condition are more likely to require replacement.
- Actual field conditions (i.e., ability to excavate, and cost of civil works required as part of cable replacement).

In addition, specific criteria for choosing between cable replacements versus cable injection include:

- If the cable segment in question is more than 200 m in length and has no more than 3 existing splices, Alectra Utilities would excavate and remove the old splice with a new splice.
- If the segment is less than 200 m in length and has 4 or more existing splices, Alectra Utilities considers the cable a candidate for replacement.
- Third-generation TR-XLPE cable that is strand-filled cannot be injected, and therefore can only be replaced.
- Cables that are older than 35 years of age are not considered for injection.

As such, only a subset of the polymeric cable population in Area 2 is eligible for cable injection. This subset of the population (shown as “Area 2” in Figure 5.3.3 - 33 below) includes only XLPE and TR-XLPE (non-strand-filled) cables. With each passing year, the cable population that is eligible for injection decreases as more cable exceeds 35 years of age, and thus more cable segments must undergo replacement. Under a strictly time-based scenario, as of 2019, Alectra Utilities will have 10 years to inject 5,169 km of eligible cable. Figure 5.3.3 - 31 below illustrates the expected volumes of injection-eligible cable over the DSP planning period. The cable population shown in Figure 5.3.3 - 31 will be assessed for suitability for cable injection as described above.

Figure 5.3.3 - 31: Available Cable Injection Population – Year over Year (km)

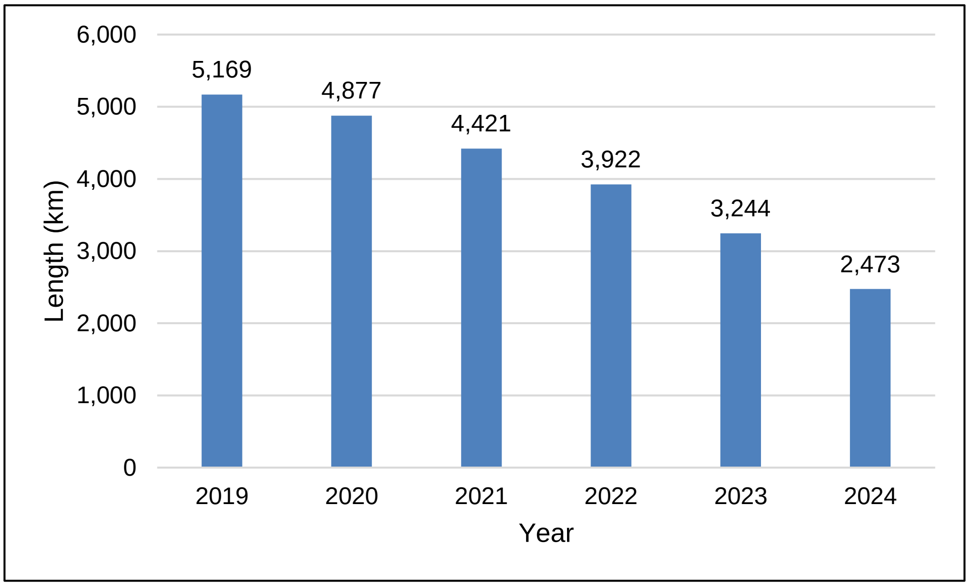
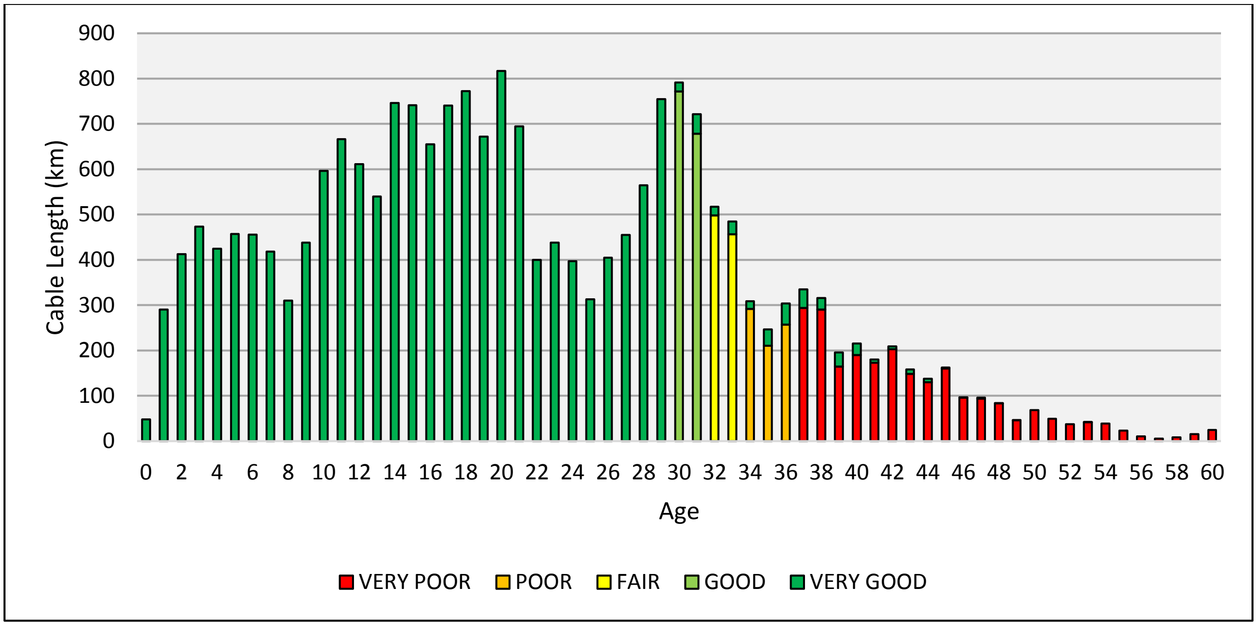


Figure 5.3.3 - 32 below illustrates the HI distribution of XLPE cables, demonstrating a direct correlation between cable age and condition. With a significant XLPE cable population already in Very Poor condition, Alectra Utilities expects that continued cable deterioration will cause more of its cables to shift toward Very Poor condition over the next five years. This impending wave of aging and deteriorating XLPE cable, if not proactively addressed, will pose a significant reliability risk for Alectra Utilities' system and customers.

Figure 5.3.3 - 32: XLPE Cable by Condition



The distribution of these XLPE cables by type is illustrated in Figure 5.3.3 - 33:

Figure 5.3.3 - 33: XLPE Cable by Type

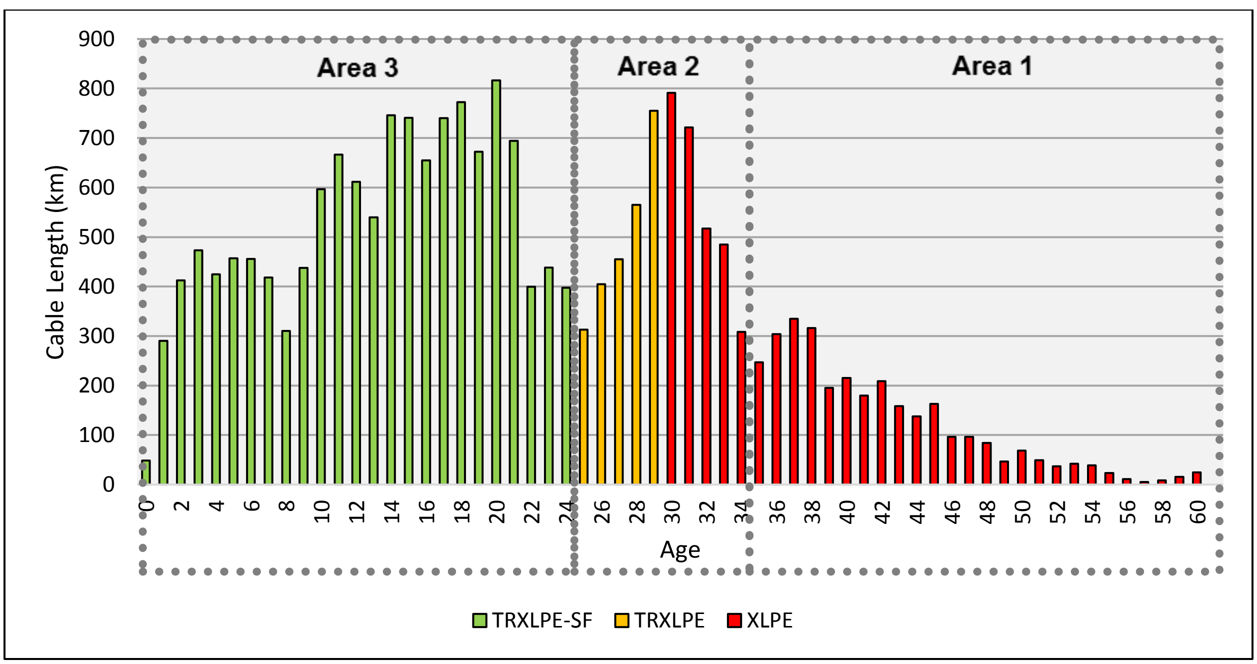


Figure 5.3.3 - 33 is further explained below:

- Area 1 consists of non-tree retardant XLPE cables, which were installed prior to 1989 and are in Very Poor condition;
- Area 2 consists of tree-retardant direct-buried XLPE and non-tree retardant direct-buried XLPE cables, which were installed from 1989 to 1993. These cables range in HI from Very Poor to Very Good and include the subset of cable eligible for cable injection.
- Area 3 consists primarily of tree-retardant or strand-blocked in-duct cables**,** which were installed post**-**1993 and are in Very Good condition.

For each "Area" shown in the above graph, Alectra Utilities has considered the cable population characteristics and the options available, as described below.

- Area 1
    - Area 1 consists of first generation XLPE cables, the majority of which are direct buried and not installed in duct. Unlike failed cables-in-conduit, which can typically be removed and replaced with new cable segments, failed direct-buried cables can only be excavated and repaired via cable splicing in a reactive situation. The installed splice may introduce a future failure point as well, particularly if the splice is not perfectly installed.
    - These cables have also been in-service the longest, and have therefore experienced more faults (and consequently, more repairs) than younger cables. Alectra Utilities' experience has shown that cables beyond 35 years in-service do not tend to be materially improved by injection. As such, the strategy is to replace these cables.
    - Cable accessories in this area are also of first-generation construction, and would be replaced along with the cable.[57]

- Area 2

[57] For example, elbows on the 27.6kV system are "non-vented," which have led to a partial vacuum flashover when operated. Splices are heat shrink or first-generation cold shrink. Terminations may be hand taped (not manufactured) which degrade faster than a cold shrink product.

- The cables shown in Area 2 consist primarily of first generation XLPE cables that are for the most part direct buried. Based on their younger age and fewer lifetime repairs, some of these cables are suitable candidates for injection. However, not all can be injected, due to the conductor used in the cables or the number of splices that a specific cable has experienced over its lifetime. Alectra Utilities will endeavour to test all cable segments eligible for injection in Area 2 and carry out cable injection accordingly to alleviate the requirements for cable replacement, while the older cables in Area 1 are being prioritized for replacement**.**
- With respect to cable accessories in Area 2, some are similar to Area 1 (i.e. older assets), while others are of newer design that have eliminated the deficiencies of the earlier versions.[58] Cable accessories will be replaced in conjunction with the cable injection or replacement process.

- Area 3
  - Cables in Area 3 are in Very Good condition and are not being considered for investment in this DSP. However, Alectra Utilities notes that many of the cables in this area are “strand-filled” and therefore not eligible for injection. When these cables begin to deteriorate, replacement is the only feasible option. However, since most of these cables are installed in ducts, Alectra Utilities anticipates that the replacement will be less expensive than for older cables.

In short, Alectra Utilities’ cable renewal strategy is to mitigate the risk of large-scale primary cable failures through a combination of cable refurbishment (using cable injection technology) and standard cable replacement practices. The utility’s focus is to address cables in Area 1 and Area 2 in the immediate term, so as to be prepared for the wave of cables (i.e., the assets that continue to age and deteriorate in Area 2 and particularly in Area 3) that will require proactive mitigation in the future, as shown in Figure 5.3.3 - 33. More specifically, this renewal strategy includes the following approaches:

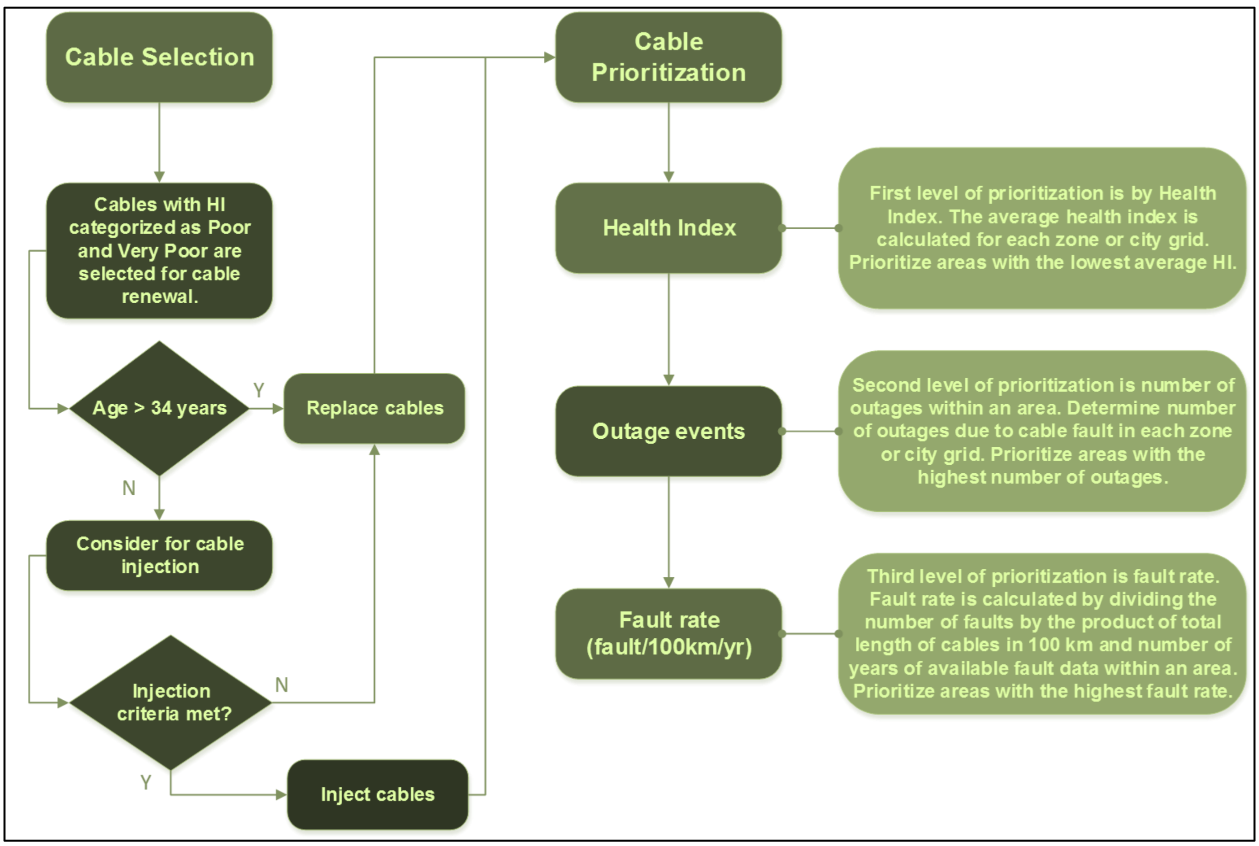
- Replace XLPE cables that are 35 years or older, targeting the non-tree retardant vintage category (i.e., cables shown in Area 1) during this DSP period.

[58] Splices, elbows, and in some cases, terminations would have to be replaced during the injection process as the fluid cannot flow through the legacy devices.

- Inject XLPE cables that are less than 35 years, targeting certain non-tree retardant, and tree-retardant and direct buried vintage categories (i.e., cables shown in Area 2) during this DSP period. XLPE cables that are candidates for injection will be tested during the preliminary injection preparation phase to determine eligibility. Those found not eligible for injection will be replaced.

After determining the XLPE cable segments that warrant renewal as part of this DSP, Alectra Utilities prioritizes the execution of replacement or injection work in accordance with the process shown in Figure 5.3.3 - 34.

Figure 5.3.3 - 34: Cable Renewal Prioritization Process



In connection with the "Injection Criteria Met?" step shown in the flow chart, Time Domain Reflectometer ("TDR") testing is performed to identify cable splices and neutral corrosion as well as estimated splice locations along the cable run. The TDR test is executed prior to cable injection to assist Alectra Utilities in deciding which cable segments will be cable injected or replaced.

Alectra Utilities assesses and implements cable renewal investments by geographical areas, so as to seek opportunities for efficiency savings (e.g., reduced logistical costs). In some cases, targeted cable replacements are carried out where warranted based on individual cable performance. As shown in Figure 5.3.3 - 34 above, the prioritization of cable renewal projects by geographical area takes into account the following main criteria:

1. HI Score: The HI scores of all the individual cable segments located within a geographical area are averaged. All areas are ranked from lowest (or worst) HI average scores to highest (or best).
2. Outages: The areas will be ranked by number of outages caused by cable faults.
3. Fault Rate: The areas will be ranked by their respective fault rate, which indicates the average rate of faults occurring on a per-km and per-year basis.

Detailed discussion regarding options analysis and pacing of the cable replacement investment are provided in Section 2.4 of Appendix A10 – Underground Asset Renewal

A9 Station Assets

Alectra Utilities' station infrastructure is critical to the transformation of high voltage supply from the transmission system to distribution voltage supply. Alectra Utilities has 14 transformer stations (TS) and 156 municipal stations (MS). TSs are supplied from the transmission grid at 115 kV or 230 kV, where MSs are supplied from the low side of TSs at 44 kV or 27.6 kV. Power transformer capacity ratings range from 75 MVA at TS, to 3 MVA at MS.

Collectively, Alectra Utilities' MS and TS have 295 transformers (of which 26 are spares), 1,271 circuit breakers and 356 switchgear units. Alectra Utilities assesses the condition of these three major station asset groups as part of its ACA.

Power transformer demographics, including spare units, are provided in Figure 5.3.3 - 35.

Figure 5.3.3 - 35: Power Transformers Age Distribution

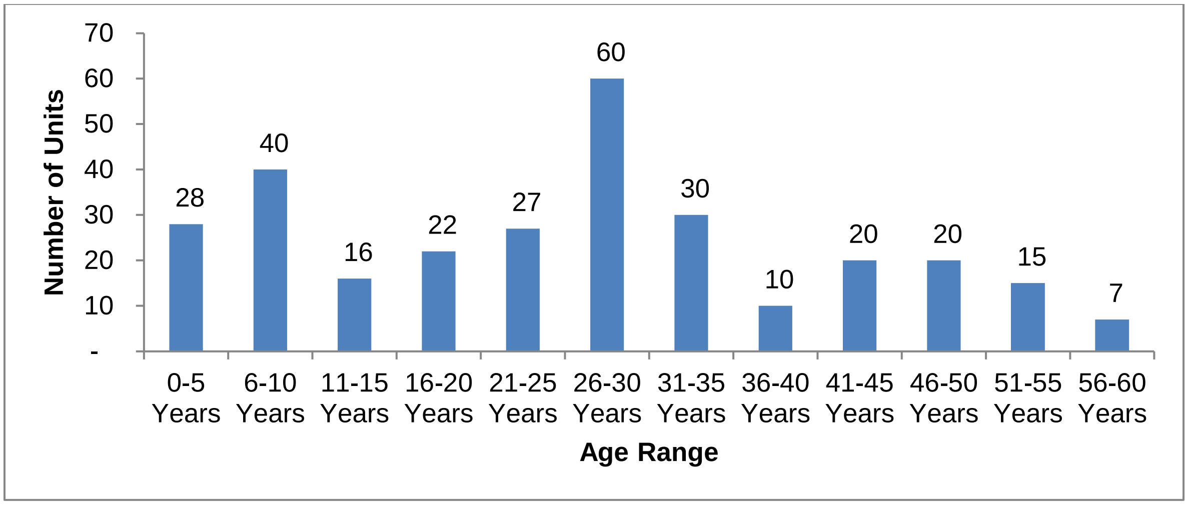
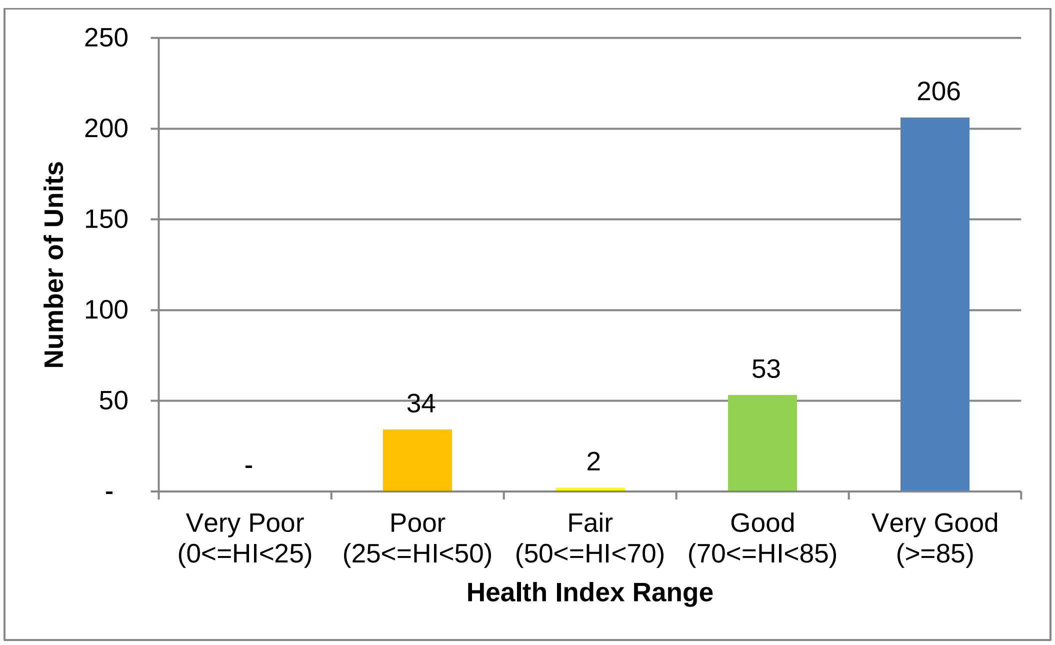


Figure 5.3.3 - 36 illustrates the power transformer HI demographics.

Figure 5.3.3 - 36: Power Transformers Health Index Distribution



Circuit breaker age demographics are illustrated in Figure 5.3.3 - 37.

Figure 5.3.3 - 37: Circuit Breakers Age Distribution

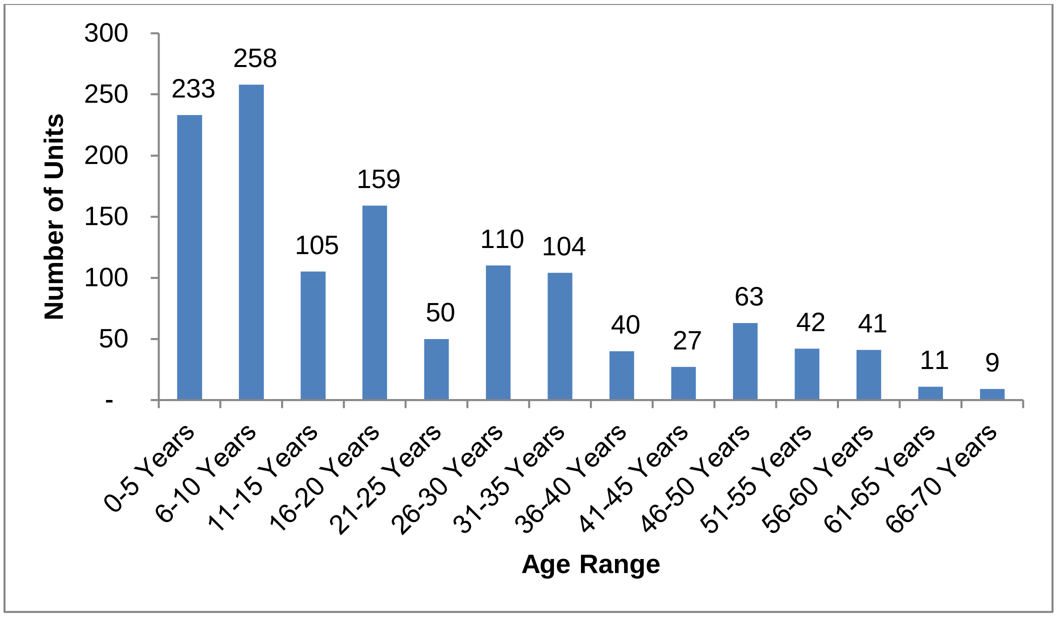
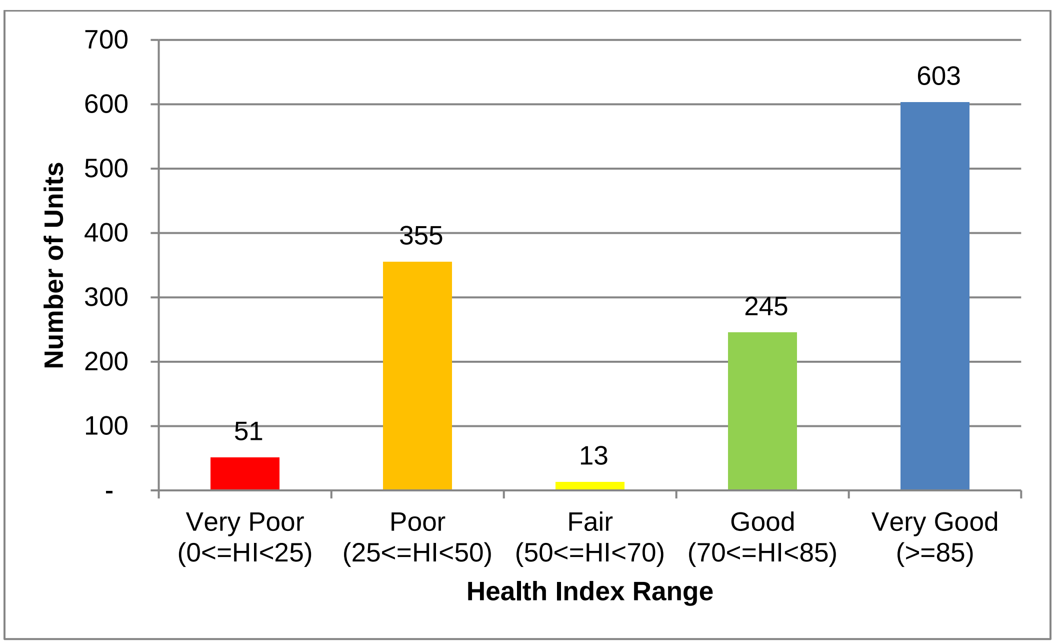


Figure 5.3.3 - 38 shows the circuit breaker HI demographics.

Figure 5.3.3 - 38: Circuit Breakers Health Index Distribution



Station switchgear age demographics are provided in Figure 5.3.3 - 39.

Figure 5.3.3 - 39: Station Switchgear Age Distribution

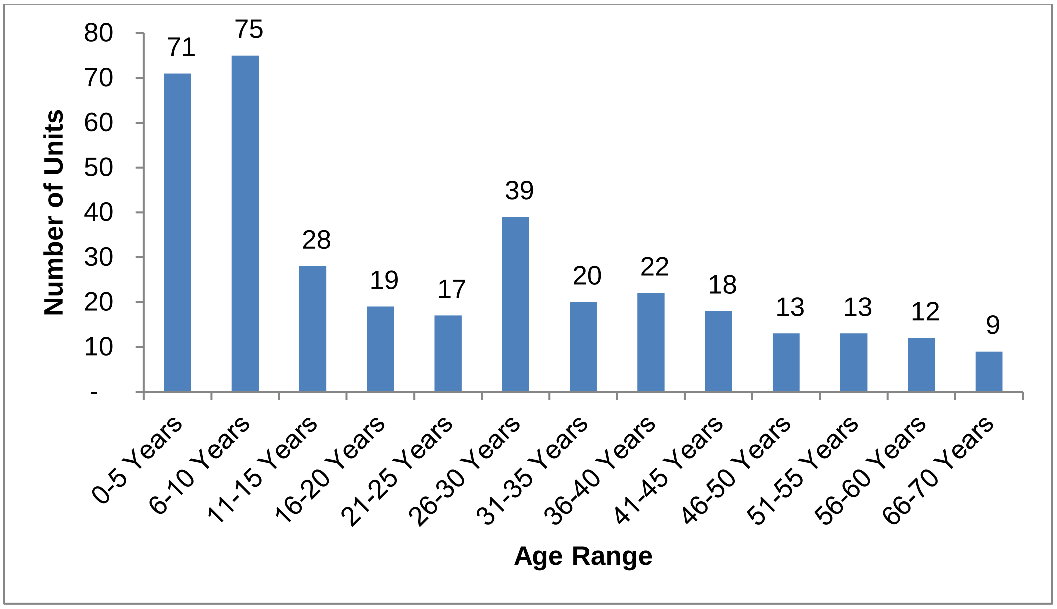
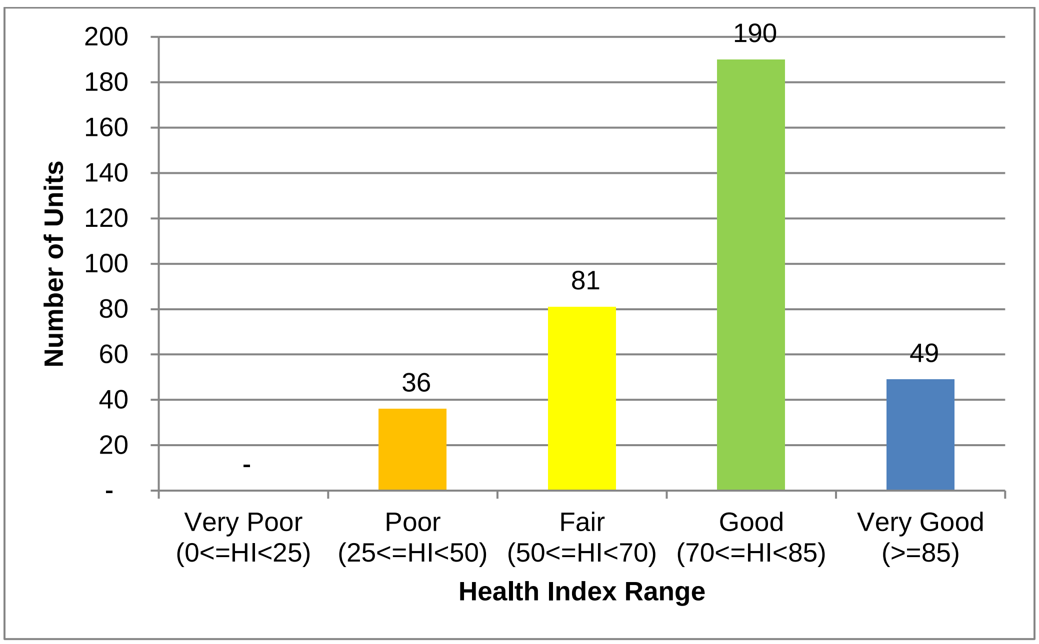


Figure 5.3.3 - 40 shows the station switchgear HI demographics.

Figure 5.3.3 - 40: Station Switchgear Health Index Distribution



According to the HI results, 34 power transformers and 36 station switchgear units are in Poor condition, and 51 and 355 circuit breakers are in Very Poor and Poor condition categories, respectively.

Alectra Utilities' assessment of station assets also covers primary switches, station protection relays, station service transformers and other ancillary equipment. Such assessment relies on the findings from stations inspection and maintenance activities.

Renewal Strategy

In addition to HI scores, Alectra Utilities' strategy in managing station assets involves the use of monitoring technologies, investing in environmental protection measures and strategically managing inventory on a consolidated basis. Refer to section 5.4.3 for further details. When considering station renewal activities multiple factors are evaluated as noted below, to assess and mitigate the risk profile at any given station:

- <u>Station configuration</u>: 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.
- <u>Inter-station connectivity and back up</u>: 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.
- <u>Spare asset inventory</u>: 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.
- <u>Station peak loading:</u> Alectra Utilities monitors station loading on a continuous basis, capturing hourly peak load values throughout the year. In the event that certain transformers exhibit high risk profiles, loading information will be used to assess offloading capabilities and the need for station asset replacements.
- <u>Station capacity upgrade projects:</u> Through the integrated planning process, Alectra Utilities will identify station sites where capacity upgrades are required and the associated

timing. 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 of the timing of the capacity upgrade and the risk profile of the existing transformers, consideration will be given to offloading, oil de-gassing and other 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.

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).

In alignment with its station-centric investment approach, 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 aforementioned 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.

B Reactive Replacement

Where asset failures pose relatively low risks (i.e., in terms of public and employee safety, environmental impact, spare parts availability, restoration duration and cost, system reliability, and customer service), Alectra Utilities generally relies on reactive replacement strategies. For example, overhead and underground distribution class transformers are typically managed on a run-to-failure basis given their low impact on customer reliability.

The timing of reactive replacements is outside the control of the utility and can require the mobilization of crews at overtime/premium rates when performed outside of normal business hours. As such, reactive replacement can be more expensive than planned replacement for some categories of assets. Further, without advanced 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. Underground primary cable failures, for example, result in unplanned disruptions for customers, impact reliability to unacceptable levels in some cases, and cost up to three times more than planned replacements.

5.3.3.3 ASSET REFURBISHMENT PRACTICES

In determining renewal investments, Alectra Utilities considers the option of refurbishment to extend an asset's useful life, based on the following factors:

- Obsolescence of asset;
- Remaining useful operating life;
- Life extension forecasted from refurbishment activity;
- Cost of refurbishment vs. cost of replacement;
- Availability of replacement parts;
- Impact to reliability (i.e., duration of refurbishment outage vs. replacement outage);
- Refurbishment warranty; and
- Cost of de-recognition if an asset is replaced.

The discussions below outline Alectra Utilities' refurbishment practices with respect to the following assets:

- Poles;
- Switchgear;
- Pole-mounted gang-operated load interrupting switches;
- Utility chambers; and;
- Stations.

A Pole Refurbishment

Through an annual inspection and testing program, Alectra Utilities monitors the condition and remaining strength of its poles to ensure that they meet minimum requirements for safety and reliability. Poles with structural defects may be assessed for the application of pole bracing/reinforcement technologies (as per CSA C22.3 No 1, Grade 1 and 2 constructions) to extend their useful life. Through pole reinforcement, Alectra Utilities can restore deteriorated poles (especially poles with major cracks**,** pole rot at ground line, or insect damage). This approach reinforces structural pole strengths and can extend the pole life span for another 15 - 25 years. This option is particularly applicable when the relevant poles are scheduled to be removed in the near future (e.g., due to road widening).

B Switchgear Refurbishment

Switchgear units are used to isolate/control other distribution equipment, and reconfigure the circuits for maintenance, restoration or other operating requirements. Padmounted switchgear units supply residential subdivisions and commercial/industrial customers. These devices are inspected on an annual basis, and condition-related observations are also made during normal operating practices. In some cases, padmounted 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 dealt with through repair (rather than wholesale replacement) include damaged fuse holders, barriers boards affected by prolonged corona exposure and cracked support insulators.

B.1 Pole-mounted Gang-Operated Load Interrupting Switches

Alectra Utilities' overhead distribution system includes a large number of manual gang-operated load interrupting switches. Through regular inspection and maintenance, Alectra Utilities assesses the condition and function of these switches. Certain minor defects can be repaired at fairly low costs to extend the life of the switch. Examples include missing rain caps, pitted contacts, faulty arc suppressors, misaligned switch blades and binding linkages.

C Utility Chamber Refurbishment

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 road ways, 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. Typically, only the upper roof slabs and a small section of the load bearing walls are impacted by this deterioration. Through regular inspections, Alectra Utilities identifies and evaluates signs of chamber structural deterioration. Where feasible, a full refurbishment of the upper deck of the chamber is carried out while leaving the remaining portion of the chamber intact.

D Substation Refurbishment

When an area of the distribution system undergoes planned renewal over a period of time (i.e., through phased projects), Alectra Utilities assesses whether the assets being retired are suitable as spare components for legacy assets. For example, where a substation is subject to decommissioning as part of a voltage conversion project or capacity upgrade, the power transformers that are removed from the station will be assessed in each case to determine their suitability as emergency spares. In such cases, the transformers will undergo condition testing to determine the extent of any refurbishment required to bring the transformer into a reliable condition for future use. Refurbished transformers offer an increased return on investment as refurbishment generally costs much less than the procurement of a new transformer. In other cases, components such as circuit breakers may no longer be supported by vendors and deemed technically obsolete. When circuit breakers are replaced, the recovered breakers may undergo testing and if deemed acceptable they will be returned to inventory to maintain spare parts that are obsolete and no longer available to source. This is intended to support remaining vintage breakers of a similar type and can be maintained to support stations that are planned to be decommissioned in the short term.

5.3.3.4 INSPECTION and MAINTENANCE PRACTICES

Alectra Utilities has two main asset portfolios for maintenance purposes: distribution maintenance and station maintenance, both of which involve planned preventative maintenance as well as predictive maintenance activities. Performed in accordance with best utility practices, preventative maintenance yields important findings and observations regarding the condition of assets in the field. Predictive maintenance targets asset performance-related parameters and includes measurement and testing. The results are then compared against normal operating ranges to identify changes in asset performance and provide an indication of the life cycle degradation of the asset.

Corrective maintenance is executed when needed based on the findings and outcomes of preventative and predictive maintenance activities. Corrective maintenance includes the replacement of components that are found to be defective, inoperable, failing, or have already failed. Effective asset maintenance reduces unplanned outages by identifying and correcting deteriorating plant before a failure occurs while maximizing related equipment life span. It also contributes to improving reliability of service. Given that effective ACA and meaningful field data are essential to any successful asset management plan, maintenance programs are important sources of additional asset data to ensure that comprehensive and accurate data underpin the ACA and resulting asset management decisions.

Alectra Utilities generally carries out maintenance activities to maximize asset value in alignment with optimal lifecycle management. Setting the appropriate inspection frequency is key to this objective. Inspections that are overly frequent will provide diminishing returns, whereas inspections that are not sufficiently frequent risks delay in identifying asset defects and premature failures. Alectra Utilities' inspection frequency is derived based on regulatory requirements, utility best practice, and manufacturer recommendations. Alectra Utilities also reviews asset performance every three years to determine if the frequency of its cyclical inspection and maintenance activities remains appropriate. The section below explains Alectra Utilities' approaches to maintenance, and the efforts taken to date to harmonize practices among predecessor utility territories.

When performing maintenance for a particular asset, Alectra Utilities crews follow the applicable maintenance procedure and also inspect the asset based on a specified list of attributes (e.g., pursuant to inspection practices recommended by manufactures, or condition factors used as inputs for ACA HI models). The primary purpose for these types of diagnostic maintenance is to determine, via visual inspections, the condition of the equipment and what repair work may be necessary. Minor repairs should be performed at the time of the inspection, where it is feasible to do so given the need to complete the planned maintenance activity within allotted time. Any defective assets that require major repair work need to be identified and flagged so that they can be scheduled for replacement. Any defective items that are urgent in nature are to be reported immediately so that timely corrective action can be implemented.

Regardless of the maintenance activity, any defects not repaired at the time of inspection are recorded and tracked to ensure appropriate mitigation is undertaken. Based on asset condition and risk (i.e., criticality, customer impact, cost, resources), the issue is scheduled for corrective action. Corrective action can be classified as “Reactive”, “Emerging”, or “Planned”. “Reactive” repairs are either completed at the time of the inspection, or scheduled as soon after as practicable. “Emerging” repairs are scheduled into the current year program. “Planned” repairs can be scheduled into the following year program.

Alectra Utilities’ maintenance programs leverage the relevant past learnings of all predecessor utilities and seek to harmonize practices. The maintenance plans reflect a mix of predictive and preventative practices to manage risks related to assets, while gathering necessary asset condition information as an input for the utility’s ACA model, which is a fundamental analytical component for purposes of identifying renewal investments. Table 5.3.3 - 3 below provides an overview of the utility’s current maintenance activities and cycles by asset type.

1 **Table 5.3.3 - 3: Overview of Maintenance Practices**

Asset	System	Predictive or Preventative	Maintenance/Inspection Activity	Cycle
Poles	Overhead	Predictive	Visual	Every 3 years
		Predictive	Wood Pole Testing	Every 7 years, until age 50 then every 5 years
		Predictive	Ground Testing	Every 14 years
Conductors	Overhead	Predictive	Visual	Every 3 years
		Preventative	Vegetation Management	Operational Area Dependent
Line Hardware	Overhead	Predictive	Visual	Every 3 years
		Predictive	Infrared	Every 3 years
		Preventative	Insulator Washing	As required by condition
Switches	Overhead	Predictive	Visual	Every 3 years
		Predictive	Infrared	Every 3 years
		Preventative	LIS Maintenance	Every 6 years
Pole mounted Transformers	Overhead	Predictive	Visual	Every 3 years
		Predictive	Infrared	Every 3 years

Asset	System	Predictive or Preventative	Maintenance/Inspection Activity	Cycle
Padmounted Transformers	Underground	Predictive	Visual	Every 3 years
		Predictive	Infrared	Every 3 years
Submersible Transformers	Underground	Predictive	Visual	Every 3 years
		Predictive	Infrared	Every 3 years
Cables and Cable Accessories	Underground	Predictive	Visual	Every 3 years
		Predictive	Infrared	Every 3 years
Switches	Underground	Predictive	Visual	Every 3 years
		Predictive	Infrared	Every 3 years
Switchgear	Underground	Predictive	Visual	Every 3 years
		Predictive	Infrared	Every 3 years
		Preventative	Dry Ice Cleaning	Every 6 years for 13.8kV or less, Every 3 years for 27.6kV
Civil Structures	Underground	Predictive	Visual	Every 3 years
	Station	Predictive	Visual	Monthly

Asset	System	Predictive or Preventative	Maintenance/Inspection Activity	Cycle
Power Class Transformers		Predictive	Oil Testing	Yearly
		Predictive	Infrared	Yearly
		Predictive	Doble	Operational Area Dependent
		Preventative	Tap Changer	Yearly
Station Protection Relays	Station	Predictive	Visual	Monthly
		Preventative	Maintenance	Operational Area Dependent
Battery and Charger	Station	Predictive	Visual	Monthly
		Predictive	Testing	Yearly
Circuit Breaker	Station	Predictive	Visual	Monthly
		Preventative	Maintenance	Operational Area Dependent

The following sections discuss Alectra Utilities' planned (i.e. preventative and predictive) maintenance practices for distribution assets and station assets.

A Planned Predictive and Preventative Maintenance – Distribution Assets

Maintenance activities classified as 'Distribution Maintenance' are for equipment not contained within a Station (either Municipal or Transformer). This covers the bulk of assets for a distribution utility: poles, transformers, switchgear, switches, wire (conductors and cables), associated line hardware, and chambers. As mentioned, maintenance activities for these assets is broken down into two categories, Preventative and Predictive. An explanation is provided for each below.

A.1 Predictive Distribution Maintenance

Predictive maintenance includes evaluating, and testing to identify conditions indicating when proactive or corrective maintenance is required to ensure that the equipment continues to meet service duty requirements.

A.1.1 Remaining Pole Strength Testing

Alectra Utilities follows a harmonized approach for wood pole testing with the standard frequency being every 7 years for poles under 50 years old, and every 5 years for poles beyond 50 years, regardless of geographical location. Wood poles with an unknown install date will follow a 5-year cycle from their last known inspection date.

Wood poles will be tested to determine remaining strength and the extent of pole degradation. The recommended testing equipment used for remaining strength is the resistograph test, which would be carried out together with pole inspection. The resistograph test involves four drill tests on each pole. The first drill would be 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, so as to measure the amount of decay and cavities inside the pole below ground level. Resistograph results indicate the percentage of the pole that contains decay or cavities. A value of 59% or above for decay or 20% or above for cavities is considered a wood pole failure. These values supply the ACA model to establish HI scores for wood pole assets.

While Alectra Utilities generally follows the harmonized inspection practice, a phased approach for implementation may be required in different operational areas of the system due to O&M

budget constraints. In such cases, Alectra Utilities plans to begin the 7-year inspection cycle at a pole age of 21 years.

A.1.2 Ground Resistance Testing

In addition to resistograph testing, Alectra Utilities also has a harmonized approach for completing ground resistance testing every 14 years, at wood poles supporting ground connections to the overhead neutral system. The recommended testing equipment used for ground resistance testing of individual ground rods is with the use of a Ground Resistance Tester. Completed using a ground resistance tester, ground resistance testing of individual ground rods provides a safety precaution to ensure grounding is intact and does not pose a risk to the public. Alectra Utilities plans to implement the harmonized approach following the completion of the relevant tendering process.

A.1.3 Infrared Scanning

Alectra Utilities has a harmonized approach for infrared (“IR”) scanning, which is also known as thermography, which is a predictive maintenance or on-condition monitoring of electrical equipment to identify anomalies and predict asset performance. Through the use of 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.

The practice across Alectra Utilities’ service territory is to target one-third of all overhead distribution plant for IR scanning. This approach reflects three major considerations: OEB visual inspection requirements, utility best practices, and ongoing review of annual inspection results to determine follow-up activities. Alectra Utilities has implemented the harmonized approach for all areas, excluding the southwest operations area, which will adopt the harmonized practice beginning in 2020.

Table 5.3.3 - 4 illustrates the criticality and response associated with various types of IR scanning results. For context, when components are inspected using IR scanning, the resulting temperature increase (compared to a particular reference point) will be used in determining criticality and response:

Table 5.3.3 - 4: 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 1 month
				Non-critical (secondary or fused)	Repair within 1 year of detection
> 10 to 20 °C	Moderate (3)	Indicates probable deficiency; repair when time permits	Document		Repair within 1 year of detection
1 to 10 °C	Minor (4)	Possible deficiency; warrants investigation	Document		Investigate/ monitor. Compare with next cycle for deficiencies

With respect to overhead plant, 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).

For underground plant, IR scanning is conducted as part of visual inspections (typically performed on padmounted equipment) and not part of the overhead IR Scanning Program.

A.1.4 Visual Inspection

Alectra Utilities' harmonized approach toward visual inspections, which is largely driven by OEB's minimum inspection requirements, entails a 3 year minimum inspection cycle with respect to urban infrastructure. More specifically, Alectra Utilities aims to visually inspect one-third of the distribution system in each year for the following asset classes:

- Poles and attachments
- Pole mounted transformers
- Padmount and submersible transformers
- Vault rooms including transformers
- Switchgear
- Civil structures and cable chambers
- Switches
- Capacitors
- Regulators

These inspections will provide Alectra Utilities with the primary condition data for its ACA process.

Due to the practical complexities in harmonizing inspection practices for such a large variety of assets, Alectra Utilities has decided to implement a harmonized approach with respect to attributes inspected (i.e., types of condition-based issues to be inspected, such as corrosion, oil leaks, overheating, mechanical damage, etc.) in a phased approach. In 2019, Alectra Utilities will inspect the following assets across its entire service area based on the same attributes:

- Padmount and submersible transformers
- Switchgear

In 2019, Alectra Utilities' West and East operating zones will adopt the new, harmonized inspection process for these additional assets:

- Poles and attachments
- Pole mounted transformers

Alectra Utilities expects all operational areas to align with the harmonized visual inspection process (based on a consistent set of attributes) by 2020.

A.2 Preventative Distribution Maintenance

Preventive maintenance includes regularly scheduled programs conducted to service and/or repair network components. These programs are normally deployed at specific time intervals and are applied to network components regardless of their apparent condition at the time. They are conducted to prevent network components from failing.

A.2.1 Load Interrupter Switch (LIS)

Alectra Utilities has a harmonized approach for LIS Maintenance. A load interrupter is one form of switch used in the overhead system. These switches are critical to enabling load transfer capabilities, work zone isolation, and emergency switching for load restoration in the event of an outage. Maintenance of LIS is considered a ‘best utility practice’ due to their critically in providing system operating flexibility and reliable power delivery to customers. The failure of an LIS to operate can lead to additional resource hours on planned work (i.e., due to the inability to operate the switch), and/or extended outage minutes to customers.

Alectra Utilities’ plans to implement a LIS maintenance cycle of every 6 years. During the maintenance process a detailed inspection will be carried out. Electrical testing and mechanical adjustments of LIS will vary according to the manufacturer’s specifications. Further, crews will record observations using a standardized checklist and file them by switch number. This information informs the selection of asset replacement under the Switch Replacement Program. As Alectra Utilities works to harmonize its practices for LIS assets, certain areas of the system may follow a different approach during the transition process until full harmonization is achieved.

A.2.2 CO_2 Dry Ice Cleaning

Air insulated switchgear is prone to tracking and failure due to the accumulation of contamination on insulating surfaces. Similar to 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.

As of 2018, Alectra Utilities is implementing a harmonized approach for dry ice cleaning on a 6-year cycle for air-insulated switchgear and vault room equipment on the 13.8 kV and lower voltage systems and on a 3-year cycle for air-insulated switchgear and vault room equipment on the 27.6 kV system, as air insulated components on the 27.6 kV voltage level has a higher susceptibility to tracking and flashover events. Additionally, targeted dry ice cleaning will be performed on vault room equipment where a need is identified through visual inspections.

A.2.3 Vegetation Management

Alectra Utilities is in the process of developing and transitioning toward a harmonized approach for vegetation planning, with harmonization across operational areas being targeted for 2020.

A.2.4 Insulator Washing

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 power interruptions. Alectra Utilities has implemented a harmonized approach for insulator washing, which prevents failures caused by tracking on high voltage overhead porcelain insulators.

Alectra Utilities implements a harmonized condition-based approach, based on inspection results to establish when insulator washing will be completed. From January to April of each year, crews will inspect known high contamination locations to determine the level of contamination and trigger insulator washing requirements where appropriate. Outside this period, no further insulator washing is completed unless a need is identified through the visual inspection and/or maintenance activities for a particular area. Repeated failures due to insulator tracking or pole fires may also trigger spot insulator washing.

B Planned Predictive and Preventative Maintenance - Stations

Maintenance activities classified as Station Maintenance are for equipment contained within a TS or MS, including power transformers, switchgear, circuit breakers, relays, busses, batteries, station services equipment, communication equipment, as well as site and civil infrastructure. Alectra Utilities' station maintenance practices have not been harmonized across different areas of the system at this time; however, maintenance frequency and maintenance practices are generally consistent. Similar to distribution maintenance, station maintenance activities also include preventative and predictive activities, as discussed below. Alectra Utilities follows the Distribution System Code Appendix C – Minimum Inspection Requirements.

B.1 Preventative Station Maintenance

Station equipment is maintained on a regular schedule. The relevant time interval can be adjusted based on operating conditions, equipment type, and operating experience with the equipment.

Preventative station maintenance activities include:

- Transformer maintenance;
- Tap changer maintenance;
- Switchgear maintenance;
- Protection relay maintenance; and
- Batteries and battery charger maintenance

B.1.1 Transformer Inspection

The following tasks are performed on every oil-filled power transformer

- In-depth inspection of transformer cooling system (check for leaks and proper operation);
- In-depth inspection of transformer bushings, cleaning, waxing if needed;
- Doble test transformer and bushings;
- Inspect pressure controls; and
- Inspect and test the tap changer.

Transformer inspection activities are based on the following documents and standards:

- Manufacturer's instructions;
- IEEE 62-1995 IEEE Guide for Diagnostic Field Testing of Electric Power Apparatus Part 1: Oil Filled Power Transformers, Regulators, and Reactors; and
- Doble transformer maintenance and test guide.

B.1.2 Tap Changer Maintenance

Oil filled tap changer maintenance activities include:

- Recording the position of the tap changer;
- Inspecting the physical and mechanical condition;
- Verifying correct auxiliary device operation;
- Verifying the correct liquid level in all tanks;
- Performing tests as recommended by the manufacturer;
- Verifying operation of heaters and grounding;
- An internal inspection which includes removing the oil and cleaning carbon residue and debris from compartment;
- Inspecting the contacts for wear and alignment;
- Tightening electrical and mechanical connections to calibrated specifications; and
- Inspecting the tap changer components for signs of moisture, cracks, electrical tracking or excessive wear and then refilling the tank with filtered oil.

B.1.3 Switchgear Maintenance

Substation switchgear maintenance is based on the manufacturer's recommendation and consists of the following work:

- Busbar, enclosure and insulator maintenance;
- External visual inspection;
- Check and tighten connections; and
- Check and clean enclosure.

B.1.4 Circuit breaker maintenance

Circuit breaker maintenance is based on the manufacturer's recommendation and consists of the following work:

- Lubricate, clean, adjust, and align control mechanism;
- Contact resistance measurement; and
- Test tripping and closing circuits.

B.1.5 Protection Relay Maintenance

Three types of relays are used to clear faults that occur in the distribution grid. The maintenance performed on each type of relay is as follows:

Electromechanical relays:

- Visual inspection;
- Mechanical adjustment and inspection; and
- Electrical tests and adjustments.

Electronic relays:

- Since there are no moving parts in these electronic relays, there is no physical wear due to usage.
- Inspection consists of secondary injection tests to verify the tripping time accuracy of the relays.

B.1.6 Battery and Battery Charger Inspection

The battery and battery charger inspection consists of the following activities:

- Record the room temperature;
- Measure and record each battery voltage; and
- Record the charging current.

B.2 Predictive Station Maintenance

Predictive station maintenance involves evaluations and tests to identify condition-based signs or indications for when proactive or corrective maintenance is required, so as to ensure that the equipment continues to meet service duty requirements.

B.2.1 Oil Testing

Power transformers undergo annual dissolved gas analysis ("DGA") and oil quality analysis. Both 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, including comparison of results of previous transformer oil samples, and provide detailed recommendations for the transformer.

DGA is performed using portable equipment as well as DGA online monitoring. Online DGA equipment is used for continuous monitoring of transformer gas concentrations and can be used to set alarms at specific gas concentration thresholds. DGA online monitoring systems are being deployed across Alectra Utilities' standard installations and can send DGA data to SCADA when an alarm threshold is reached.

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.

B.2.2 Doble Testing

Doble testing is used to assess the overall power factor, winding turns ratio, leakage reactance and excitation current of the transformer. 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, DGA testing and oil quality analysis complement each other to provide a clear indication of the overall health of the transformer.

B.2.3 Battery Testing

Annual battery 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 substation equipment control.

B.2.4 Infrared Scanning

Similar to 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.

5.3.3.5 IMPACT OF SYSTEM RENEWAL ON MAINTENANCE

Alectra Utilities' system renewal investments are designed to replace functionally obsolete, deteriorated and end-of-life assets. Such assets often require increased inspections and maintenance to ensure continued satisfactory performance until they are removed and replaced. Alectra Utilities anticipates that system renewal investments targeting certain legacy distribution system assets will contribute to a gradual and modest reduction in required maintenance under specific circumstances, as such legacy assets decline in quantity and are replaced with newer, standard equipment that typically requires less maintenance. These assets include but are not limited to:

- legacy porcelain insulators: replacing these units with standard polymer insulators eliminates the requirement for insulator washing and reduces the scope of IR scanning activities associated with overhead lines.
- legacy air insulated padmounted switchgear: replacing these units with current standard solid dielectric switchgear eliminates the requirement for dry ice cleaning.
- legacy overhead switches: replacing these units with sealed automated switches eliminates the need to perform routine maintenance on the legacy switches.

At the same time, the installation of increasing volumes of newer assets, which potentially entail new maintenance standards and practices, may result in incremental O&M costs. Further, certain ongoing planned maintenance activities are generally uncorrelated with system renewal expenditures, in particular: (i) maintenance activities following disruptions and damages caused by emergencies or major weather events, (ii) scheduled inspections that must comply with the OEB's minimum inspection requirements, (iii) corrective maintenance activities to address issues stemming from ongoing asset deterioration and external factors (e.g., exposure to environmental elements, animals, insects, vegetation); and (iv) vegetation management to ensure that clearance requirements for overhead assets are met.

Alectra Utilities plans to build upon the current implementation of station reliability centred maintenance ("RCM") in one of its operating areas and expand it across the utility's service territory. In this regard, the company will direct maintenance efforts to target assets displaying signs of deterioration while reducing maintenance on assets in good condition. A key benefit of RCM is that the scope and frequency of maintenance activities are adjusted based on the observed asset condition and performance over time. As such, RCM is more closely aligned with asset operating condition, resulting in a more tailored and effective approach to station maintenance. To the extent station renewal investments lead to improved asset condition and performance, this may result in certain O&M cost savings due to reduced RCM activities for those particular assets, depending on the corresponding maintenance frequency and activities.

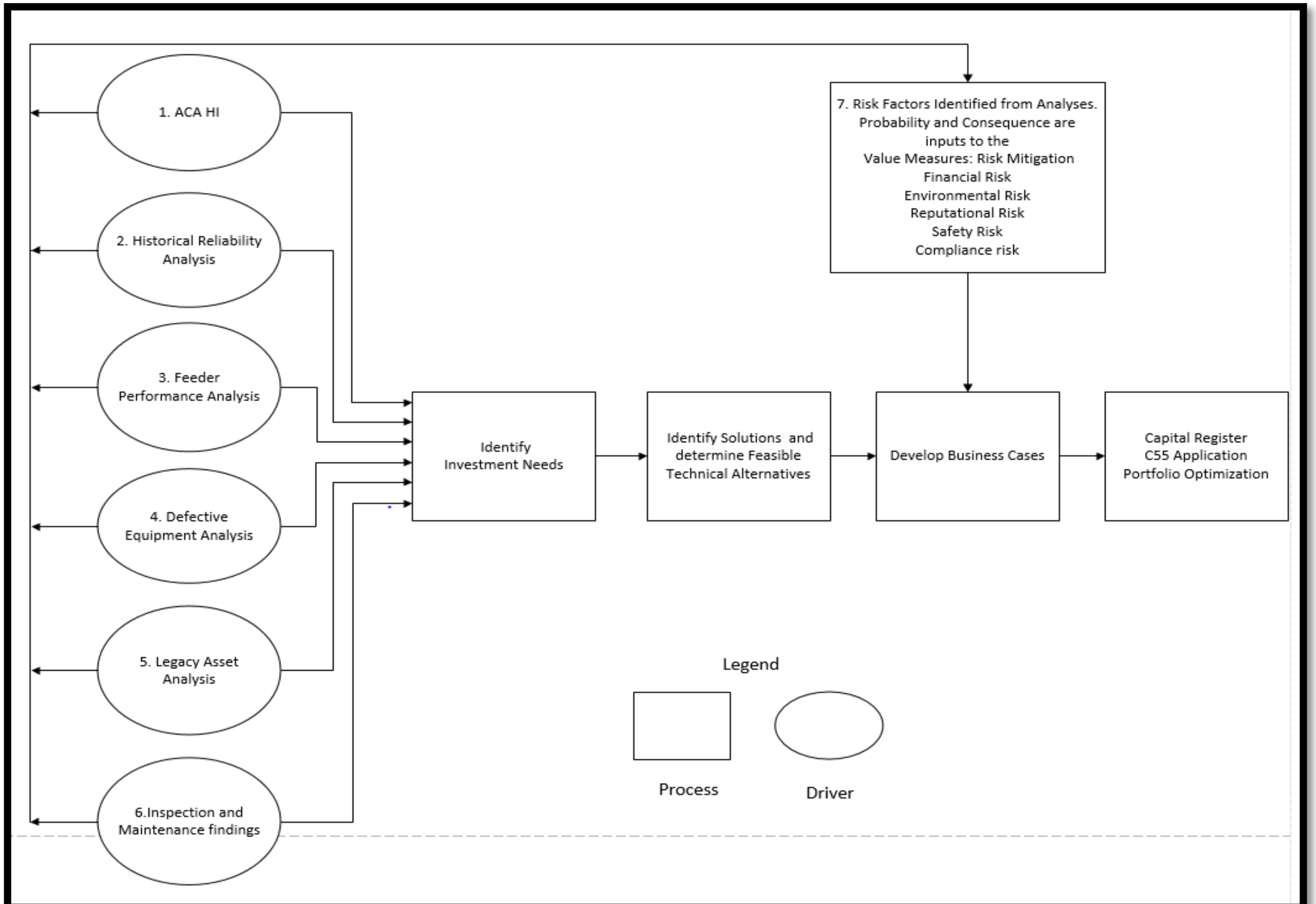
As part of the evaluation of the financial benefits and costs associated with system renewal investments, Alectra Utilities determines and assesses, where applicable, each candidate project's impact on OM&A expenditures, whether as savings or additional cost pressures. As detailed in Section 5.4.1, this assessment forms part of the standard financial evaluation performed through the CopperLeaf C55 system.

5.3.3.6 ASSET LIFECYCLE RISK MANAGEMENT

Alectra Utilities' asset lifecycle risk management practices incorporate information obtained from multiple asset management-related processes and applications including: ACA, Historical Reliability Analysis, Equipment Failure Analysis, Worst Performing Feeder Analysis, Legacy Asset Analysis and Equipment Loading. Alectra Utilities has integrated these processes and inputs in order to thoroughly consolidate and evaluate information related to asset condition, asset functionality (i.e., relative to current specifications and standards), and risk of failure. The outcome of these processes provides the utility with lagging indicators trends in system performance and, by extension, customer experience.

Alectra Utilities' approach to asset lifecycle risk management follows good utility practices, including the preventative and predictive maintenance activities described in section 5.3.3.4. These activities support asset risk management measures designed to identify substandard asset performance and conditions, and actionable items for correction and mitigation. Such maintenance activities are key to the ongoing sustainment of assets in alignment with the optimal asset lifecycle. In addition to maintenance activities, Alectra Utilities inspects assets according to the minimum requirements outlined in Appendix C of the OEB's Distributions System Code. Information obtained from underground and overhead inspection and maintenance activities informs the identification and development of appropriate failure risk mitigation approaches, and yields important asset condition data that underpins the ACA process, which is described below. Figure 5.3.3 - 41 illustrates the high-level relationship among the key analyses that Alectra Utilities undertakes in this regard and how their output feeds into the process of identifying asset-related risks and developing risk mitigation solutions (i.e., as part of Alectra Utilities' asset management and capital planning process, as discussed in Sections 5.3.1 and 5.4.1 of this DSP). The figure is followed by a description of each type of analysis.

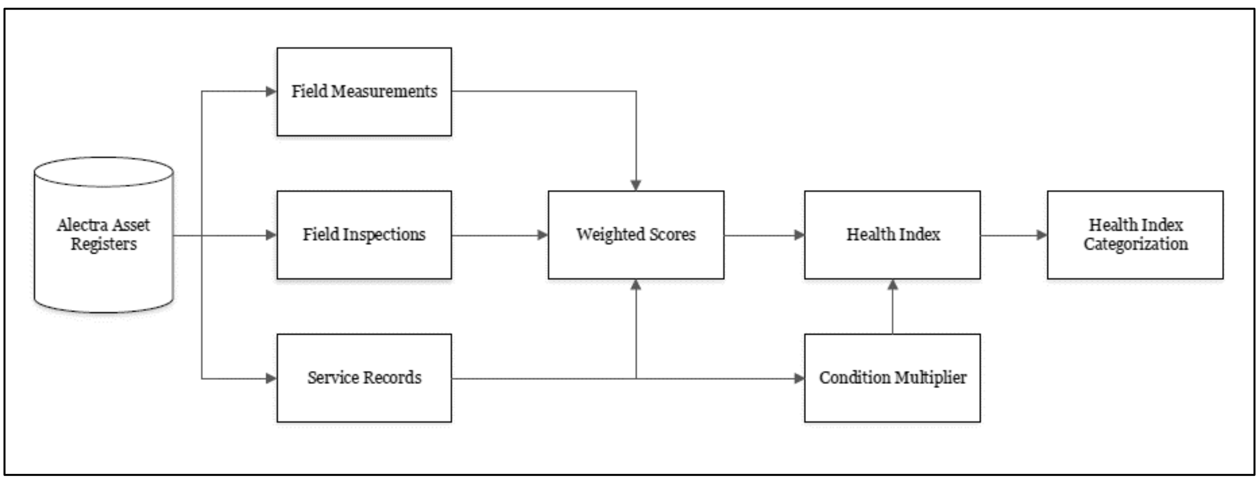
Figure 5.3.3 - 41: Asset Lifecycle Risk Management Processes



A ACA

Alectra Utilities' ACA utilizes data collected through inspection and maintenance activities to produce a numerical representation of asset condition, taking into account key factors that affect asset operation, degradation, and overall lifecycle. The ACA provides valuable information regarding the condition demographics of each asset class. It also allows the utility to identify trends in asset condition degradation as successive ACAs are conducted over time. Such trend analysis is useful in identifying declining or improving HI values, as a useful indication of areas where renewal investment levels should be increased to mitigate anticipated issues (e.g., impending wave of degrading assets, such as underground primary cables, that will require significant attention) or redirected to target high risk assets. Furthermore, Alectra Utilities' ACA and HI calculations are done for each physical asset processed through the models, leading to a high level of granularity that supports the effective identification and prioritization of assets for refurbishment or replacement. An overview of Alectra Utilities' ACA process is illustrated in Figure 5.3.3 - 42.

Figure 5.3.3 - 42: ACA process



The HI is an analytical model that quantifies asset condition based on weighted inputs in a consistent manner. The number and type of input parameters (based on applicable service records, maintenance and inspection records, third party test results, and subject matter expert ("SME") input) vary depending on the specific asset class and available data. The weighting of input parameters is based on the asset class, industry guidelines, and Alectra Utilities' experience operating and managing the assets.

As part of the 2018 ACA process, the company derived HI scores for the following asset classes:

- Distribution transformers
- Distribution switchgear
- Overhead switches
- Overhead conductors
- Wood poles
- Concrete poles
- Underground primary cables
- Power Transformers
- Circuit Breakers
- Station Switchgear

The HI score of an asset is expressed as a percentage. When categorized based on ranges, the HI scores provide an indication of each major asset demographic across the HI spectrum (from Very Poor to Very Good, per table below), enabling the identification of groups within an asset class that exhibit similar characteristics from an overall condition perspective. The HI is classified into one of five categories as shown in Table 5.3.3 - 5.

Table 5.3.3 - 5: Health Index Categories

Category	Criteria	Range
Very Good	Asset is in excellent condition.	$HI \geq 85\%$
Good	Asset is still relatively in excellent condition.	$70\% \leq HI < 85\%$
Fair	Asset is functional but showing signs of deterioration.	$50\% \leq HI < 70\%$
Poor	Asset is exhibiting degraded condition.	$25\% \leq HI < 50\%$
Very Poor	Asset is showing major degradation / imminent failure.	$HI < 25\%$

Alectra Utilities' engineers examine the HI outputs of the ACA in conjunction with inspection results and professional judgement to identify short term investment needs required to address priority deficiencies and risks. Together with HI scores, the outputs from historical reliability analysis, equipment failure analysis, worst performing feeder analysis, asset utilization and legacy asset analysis (each further discussed below) are used to establish risk profiles for various asset types under review. Alectra Utilities' engineers assess the probability and consequence of failure in order to establish a risk score for each proposed investment. The results are used when identifying technical solutions and the risk scores are calculated as part of the business case development for the recommended alternative.

In addition, proposed asset renewal investments are examined in the context of longer-term (i.e. 5 year) investment plans. Alectra Utilities assesses the asset class failure rates over a fifteen year horizon beyond the DSP planning period to project the impact of replacement rates on future asset demographics.[59] This process enables Alectra Utilities to more effectively manage investment renewal pacing in subsequent DSP planning periods, so as to minimize significant fluctuations in investment needs, avoid sudden rate impacts on customers, and ensure optimal resource planning. Having a long-term view of asset demographics allows the company to more effectively optimize the value of planned capital investments according to projected asset needs.

B Historical Reliability Analysis

Alectra Utilities monitors and tracks annual reliability based index measures excluding outages related to Major Event Days. The results provide SAIFI and SAIDI values, which are reflective of the average frequency and duration of power interruptions experienced by Alectra Utilities' customers. The company further examines outage events to understand the root causes of outages, where there are distribution system vulnerabilities, as well as system maintenance and sustainment needs in order to mitigate the impacts of similar events in the future. While these values are calculated as system averages, they provide a high-level indication of reliability trends over time and are used to help identify changes in system reliability performance.

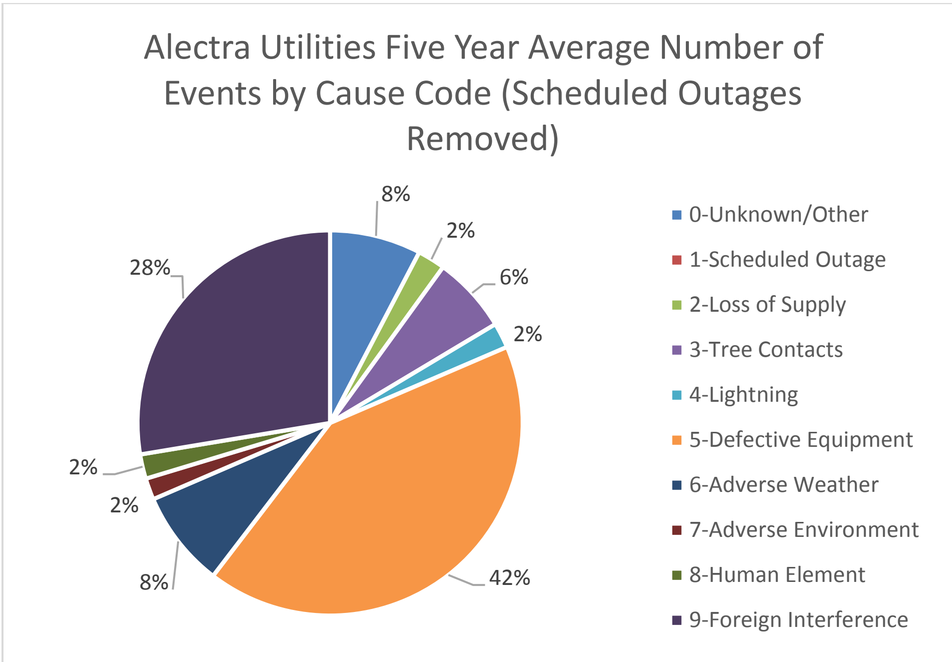
[59] Twenty year asset failure rates were calculated using the Typical Useful Life and Maximum Useful Life as provided in the "Asset Depreciation Study for the Ontario Energy Board" prepared by Kinectrics Inc., Report No: K-418033-RA-001-R000 (July 8, 2010).

At a more granular level, Alectra Utilities examines the Factors Contributing to Adverse Trends in SAIDI and SAIFI by performing an analysis of its outage 'cause codes', which are part of the company's system of identifying and tracking the root causes of outages affecting system equipment and customers. These cause codes, which align with the OEB System Reliability Standards, categorize the main causes of outages as follows:

- Defective Equipment Failure
- Adverse Environment
- Adverse Weather
- Foreign Interference
- Tree Contact
- Lightning
- Human Element
- Loss of Supply
- Scheduled outages
- Unknown

Figure 5.3.3 - 43 below, is taken from page 16 of Section 5.2.3 and provides an example of the breakdown of codes analysed by the company to better understand the trends and risks impacting system reliaility.

Figure 5.3.3 - 43: Alectra Utilities Five Year (2014-2018) Average Number of Events by Cause Code (Excluding Scheduled Outages)



As is evidenced by Figure 5.3.3 - 43, over the last five years defective equipment is the leading contributor in both duration and frequency of outages followed by foreign interference. These statistics inform Alectra Utilities of reliability risks and associated trends, and indicate where efforts are required to develop remedial solutions.

C Feeder Performance Analysis

Alectra Utilities manages reliability performance at the feeder level, which provides insight into specific areas with substandard performance, i.e., due to a long duration of outages, high frequency of outages, high number of momentary outages or a combination of the foregoing.

On an annual basis, Alectra Utilities assesses feeders and identifies the worst performing ones based on: number of outage events, number of momentary outages, duration of outages as well as a combination of events and duration. For example, feeders which significantly contribute to SAIDI or SAIFI, or experience significant momentary outages year after year are flagged as part of this analysis. Alectra Utilities identifies these feeders by service area and develops a list of feeders which have poor reliability for further assessment. The resulting findings help inform where enhanced maintenance requirements or renewal investments can be implemented.

D Defective Equipment Analysis

Alectra Utilities further analyzes each asset category within the cause code to better understand the root causes of defective equipment outages. This analysis provides detailed information on equipment failures, which facilitates risk mitigation through system renewal investments and maintenance activities. Figure 5.3.3 - 44 and Figure 5.3.3 - 45 below, are taken from pages 23 and 24 of Section 5.2.3, respectively, to demonstrate the four major sub-causes that account for 91% of all defective equipment interruption hours at Alectra Utilities (and its predecessors) from 2014 to 2018. The distribution of defective equipment outage causes by specific asset sub-classes as shown in Figure 5.3.3 - 45 provides a more detailed reflection of equipment-related failures and provides Alectra Utilities with a clear indication of the assets most vulnerable to failure risks. Outputs from this analysis support the identification of assets having the highest impact on system reliability and where investments can be focused to manage poor or declining reliability.

Figure 5.3.3 - 44: Alectra Utilities 2014-2018 Sub-Causes of Defective Equipment

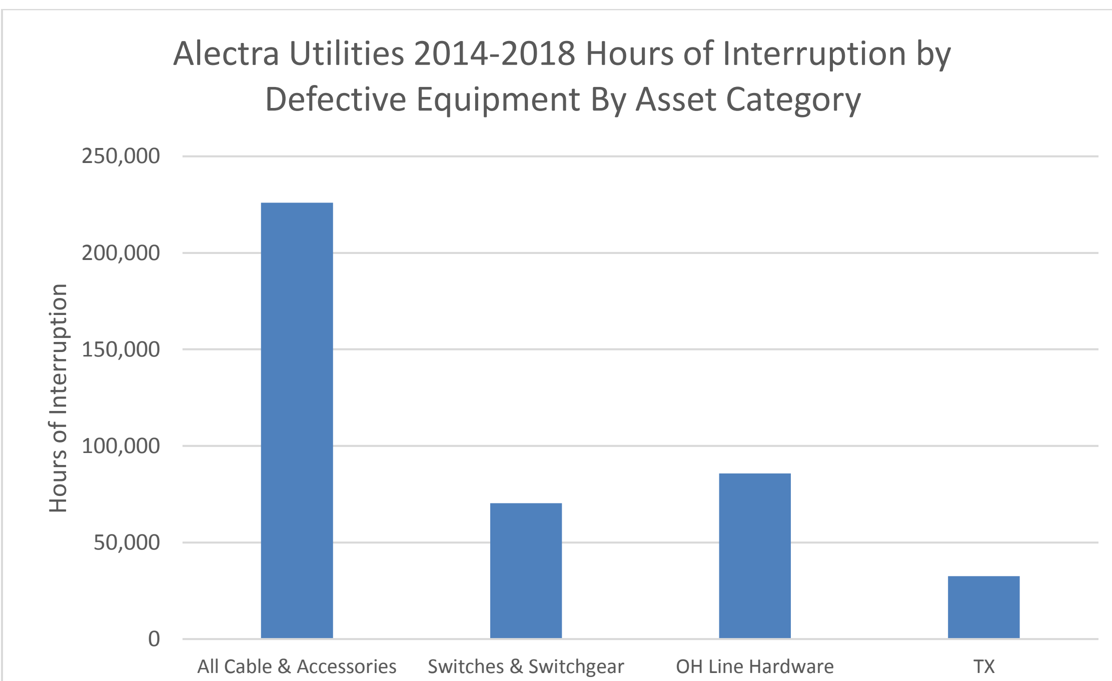
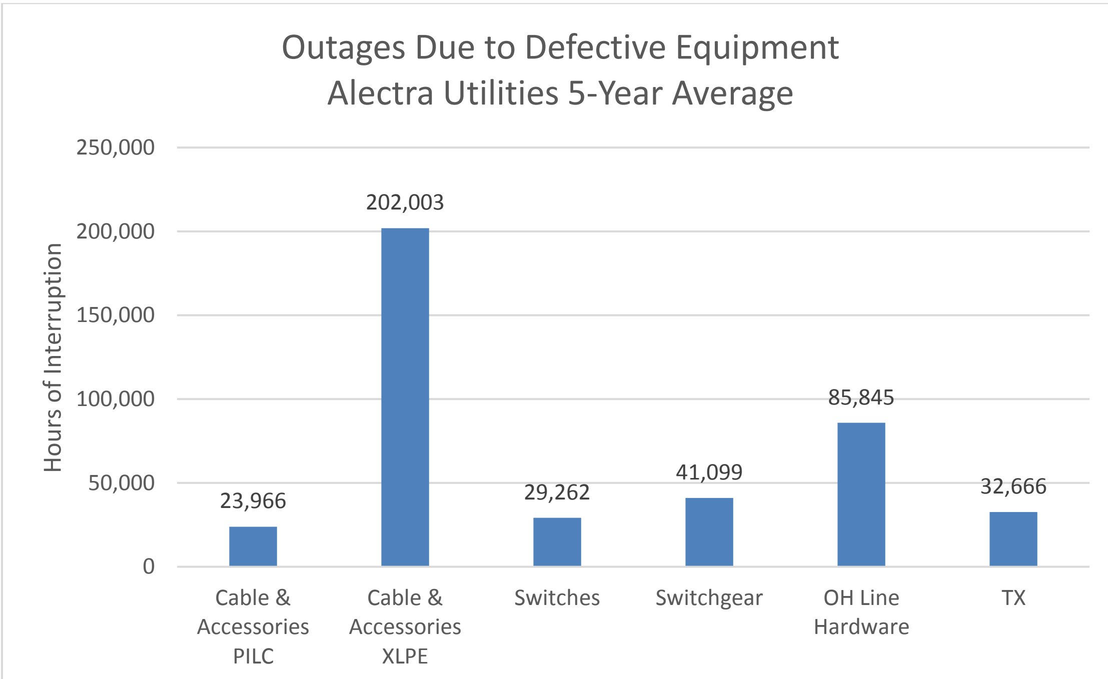


Figure 5.3.3 - 45: Alectra Utilities 5 Year (2014-2018) Average Sub-Cause Defective Equipment Specifics by Customer Hours of Interruption Modified to Account for Switchgear Failures



E Legacy Asset Analysis

Alectra Utilities' risk assessment practices include the identification and evaluation of legacy assets which no longer conform to current standards. Such assets may be of a legacy configuration that no longer align with current operating practices or standards, and therefore are deemed functionally obsolete. Equipment that is functionally obsolete may pose system operating constraints or safety concerns. An example is live front padmounted transformers, where the high voltage compartments contain energized components or where station switchgear line ups do not incorporate arc chutes. Other legacy configurations may be functionally obsolete and are no longer supported by the vendor or aftermarket services. These assets are identified in system inventories and managed such that spare parts are obtained from decommissioned assets of similar vintage when available. The reduction and eventual elimination of these assets are paced over time while managing the remaining in service asset risks.

F Inspection and Maintenance Findings

Ongoing inspections and normal equipment operating practices often reveal substandard asset condition and performance issues. Asset Management Engineers review the resulting documented findings and conduct analyses that assist in identifying correlation with other substandard performance indicators. The results are valuable in terms of clarifying substandard asset performance trends and asset risks which will ultimately require risk mitigation through renewal or enhanced maintenance.

G Equipment Duty and Loading

Asset operating duty and asset loading, are monitored to ascertain if equipment is operating within manufacturer specifications or ratings. Where assets are found operating with greater duty requirements or loading beyond the manufacturer's specifications the asset will further assessed. Asset Management Engineers will review the frequency of occurrences and duration where manufacturer's specifications have been exceeded and will determine if asset renewal is warranted or if alternative mitigating options are available.

H Risk Factors

When designing the asset lifecycle optimization process and sustainment approach for its fleet of distribution assets, Alectra Utilities considered risk of asset failure at the asset class level. Risk assessment was performed on asset classes based on failure and consequence of failure, on safety, environment, and system reliability. The outcome of the risk assessment is incorporated in the methodology followed for asset sustainment, namely to decide on the renewal strategy: no action, further assessment, continue to monitor, proactive replacement, maintenance or rehabilitation. An example of this methodology can be demonstrated for the risk assessment performed for the failure of a typical oil filled single phase distribution class padmounted transformer. This asset class is typically operated on a run to failure basis because the failure of a pad mounted transformer would result in loss of supply to a small number of customers, typically less than 15. However, the company will initiate proactive replacement if, in the course of inspections and normal operating activities, a transformer is found in a deteriorated condition that poses risk to public or employee safety (e.g. corroded or damaged physical structure and compromised enclosure of energized components), risk of environmental contamination (e.g. containing PCB or showing signs of leaking oil), or identified to be overloaded.

Similar risk assessments were performed on other asset classes. For the pole asset class, the risk of failure and consequence of failure, on safety, environment, and system reliability was evaluated. The result of a pole failure was deemed to have a very high impact on public safety and therefore this asset class is operated on a proactive replacement strategy. Further granularity on the pole configuration is used to prioritize replacement candidates from a portfolio of poles deemed to be in deteriorated condition.

Alectra Utilities' practice to assess risk, has evolved from an age based determination to a more advanced condition based risk determination. Enhanced and consistent inspection practices were implemented in a harmonized manner across Alectra Utilities' service territory. This facilitated the collection of improved condition data, which in turn supported the determination of asset lifecycle risk based on specific asset condition parameters representative of asset degradation for each given asset category. The output of the ACA identified groupings of assets in Very Poor and Poor condition. These results were combined with reliability metrics to identify assets demonstrating declining performance negatively impacting customer service levels. The combination of condition and reliability was used to identify which asset classes Alectra should examine further. Using asset criticality within each asset grouping, Alectra Utilities was able to narrow down investment needs (by asset class) for the organization and it was from these needs, that Alectra initiated the creation of business cases.

This process was used to identify system renewal investment needs and to support development of technical alternatives to mitigate the risks identified. This information was used to facilitate selection of a recommended alternative for business case development and investment portfolio optimization in the CopperLeaf C55 application. C55 incorporates a Value Framework, which utilizes a methodological algorithm to determine the overall value of each potential investment in addressing relevant risks and needs. The Value Framework allows Alectra Utilities to analyze and score each potential investment's benefits, costs and risk mitigation effectiveness, known as Value Measures. The outputs from the processes described above are used as inputs for the Value Framework and support the scoring of relevant risks. The specific Value Measures used in distribution asset risk assessments include the following risks: financial, environmental, reputational, safety and compliance. Assessment of System Capacity risks are addressed separately in section 5.3.1. Risk Value Measures are aligned with the company's Enterprise Risk Management ("ERM") framework, particularly in terms of risk definition, categories of risk, risk impact as well as the criteria to derive the probability of likelihood risk materializing. Risk Value Measures are combined in a Risk Matrix (See Figure 5.4.1 - 1 CopperLeaf C55 Risk Matrix in section 5.4.1) that identifies the levels of risk for each measure. The matrix defines the impact at each level to guide the evaluation of each risk identified for a project. For further details on the Value Framework and Capital Expenditure Planning Process refer to section 5.4.1.

Alectra Utilities has commenced aggregating large samples of failure data, maintenance data and inspection data. This is being performed to develop uniform data sets with high levels of granularity reflective of Alectra Utilities' experience. The organization is continuing to evolve its asset management practices to include the development of refined asset failure probability curves in order to begin the evaluation of the failure risk of specific assets with in each grouping. Alectra expects that this level of analysis will aid in the identification and prioritization of individual asset renewals within each asset category. Over the next few years, Alectra will begin to focus its efforts on the next DSP and will be evolving its Asset Register and asset models using customer outage costs and failure curves.

I Renewal Investment Impact on 20 Year Failure Projections

Alectra Utilities forecasts the asset class failure rates over a fifteen year horizon beyond the DSP planning period to project the impact of replacement rates on future asset demographics.[60] This process enables Alectra Utilities to more effectively manage investment renewal pacing in subsequent DSP planning periods, so as to minimize significant fluctuations in investment needs, avoid sudden rate impacts on customers, and ensure optimal resource planning. Having a long-term view of asset demographics allows the company to more effectively optimize the value of planned capital investments according to projected asset needs.

[60] These twenty year asset failure rates were calculated using the Typical Useful Life and Maximum Useful Life as provided in the "Asset Depreciation Study for the Ontario Energy Board" prepared by Kinectrics Inc., Report No: K-418033-RA-001-R000 (July 8, 2010).

5.3.4 SYSTEM CAPABILITY ASSESSMENT FOR RENEWABLE ENERGY GENERATION AND GRID MODERNIZATION

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.

This section also details Alectra Utilities approach to grid modernization. Investments in grid modernization are largely in foundational systems to meet the challenges posed by the drivers, such as to advance capacity for bi-directional energy management, automated restoration, improved communication, condition monitoring, system hardware and software upgrades, and cyber security.

5.3.4.1 HISTORICAL AND FORECAST REG CONNECTIONS

As of October 2018, Alectra Utilities has 5,504 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 150 MW of generation capacity. Table 5.3.4 - 1 shows the total number of connected REG projects in Alectra Utilities' service area by type as of October 31, 2018.

Table 5.3.4 - 1: Total Connected REG Projects (As of Oct. 31, 2018)

Totals	Number	MW
Total Connected FIT	564	108.4
Total Connected microFIT	4845	39.5
Total Connected Net Meter	95	2.4
	5504	**150.3**

The connected FIT projects consist of 108.4 MW of REG facilities that all use solar energy technologies. The connected microFIT projects (totaling 39.5 MW) consist primarily of solar generation facilities and 1 wind project (1.8 kW). The connected net metering projects (totaling 2.4 MW) consist primarily of solar generation facilities and two wind projects (51.5 kW).

In addition to the connected REG projects, Alectra Utilities has received 54 REG connection applications for a total of 8.89 MW of projects that are yet to be connected to its system. In particular, as of October 2018, the company had received applications for and approved the connection of 20 FIT projects (totalling 5.19 MW), 13 microFIT projects (totalling 0.09 MW) and 21 net metering projects (totalling 3.6 MW). As of October 2018 these projects were completing their development processes or being constructed.

Due to the cancellation of the FIT and microFIT programs, Alectra Utilities is expecting a significant drop in the number of REG connection applications it receives going forward, with a total of only 130 net metering applications anticipated in 2019. A summary of the company's historical and projected REG connections is provided in Table 5.3.4 - 2, below.

Table 5.3.4 - 2: Actual, Projected and Forecast Volumes for REG Connections (including FIT/microFIT/Net Metering) as of October 2018.

Year	Applications/year	Connected Capacity/year (kW)	Cumulative Applications from 2016	Cumulative Connected from 2016 (kW)
2016	827	11,366	827	11,366
2017	929	25,174	1,756	36,540
2018	882	16,273	2,638	52,813
2019	130	2,725	2,768	55,538
2020	224	2,160	2,992	57,698
2021	272	2,400	3,264	60,098
2022	199	2,035	3,463	62,133
2023	142	1,750	3,605	63,883
2024	108	1,535	3,713	65,418

The forecast for 2020-2024 reflects the characteristics of Alectra Utilities' service area and the effects of recent policy changes. Alectra Utilities' service area consists predominantly of urban regions, which are more suited to rooftop solar rather than larger ground mount solar or wind energy projects (which have attracted limited interest). In light of recent regulatory developments, including the conclusion of the FIT program, repeal of the *Green Energy Act, 2009*, introduction and subsequent replacement (through Bill 87) of the Ontario Fair Hydro Plan (both of which have the effect of reducing consumer bills so as to make net metering less attractive), Alectra Utilities expects the volume of REG connection applications in its service territory to be significantly lower going forward as compared to previous years.

More specifically, after an anticipated sharp decline in connection applications in 2019 due to the conclusion of FIT and microFIT, Alectra Utilities expects the volume of applications to remain low through to 2024. Between 2019 and 2024, Alectra Utilities forecasts roughly 1075 additional REG connections (net metering) totalling 9.8MW to its distribution system.

5.3.4.2 STATION CAPACITY FOR CONNECTION

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 is able to 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 5.3.4 - 3 and Table 5.3.4 - 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 5.3.4 - 3: Alectra Utilities-Owned TSs – Remaining DG Station Capacity

Connected Transformer Station Alectra Utilities Owned	TS Thermal Capacity (kW) (Max Rating)	Total Connected DG Capacity (kW)	Estimated Remaining TS Capacity (kW)
VAUGHAN MTS #1	8,716	4,321	4,395
VAUGHAN MTS #1 E	107,860	4,374	103,486
VAUGHAN MTS #2	7,640	3,295	4,345
VAUGHAN MTS #3	106,230	3,279	102,951
VAUGHAN MTS #4	82,500	6	82,494
RICHMOND HILL MTS #1	9,310	2,587	6,723
RICHMOND HILL MTS #2	38,496	1,953	36,543
MARKHAM MTS #1	38,850	3,107	35,743
MARKHAM MTS #2	42,580	4,007	38,573
MARKHAM MTS #3	41,840	1,802	40,038
MARKHAM MTS #3E	43,504	1,453	42,051
MARKHAM MTS #4	94,740	1,369	93,371
JIM YARROW MTS A	28,125	2,284	25,841
JIM YARROW MTS B	28,125	4,376	23,749
ARLENE MTS	33,000	11,446	21,554
		Maximum Capacity (kW)	661,857

1 **Table 5.3.4 - 4: HONI-Owned TSs – Remaining DG Station Capacity[61]**

Connected Transformer Station HONI Owned	TS Thermal Capacity (kW) (Max Rating)	HONI Allocated Capacity (kW)	Total Connected DG Capacity (kW)	Estimated Remaining TS Capacity (kW)
EVERETT TS	63,800	2,000	2,685	61,115
HOLLAND TS	96,600	2,000	1,089	911
MIDHURST TS DESN1	119,400	3,500	1,820	1,680
MIDHURST TS DESN2	71,500	5,000	2,319	2,681
BARRIE TS	68,500	5,000	2,800	2,200
AGINCOURT TS	59,600	1,000	200	800
ALLISTON TS	61,600	N/A	8	61,592
ARMITAGE TS DESN 1	119,600	4,000	1,460	2,540
ARMITAGE TS DESN 2	120,400	4,000	1,535	2,465
BUTTONVILLE TS Z Bus	34,000	5,000	2,033	2,967
BUTTONVILLE TS Q Bus	38,800	5,000	2,816	2,184
FAIRCHILD TS DESN 1 BY	36,800	2,000	342	1,658
FAIRCHILD TS DESN 2 J	27,200	N/A	65	27,135
FINCH TS DESN 1	40,700	2,000	510	1,490
KLEINBURG TS*	46,000	N/A	0	0
LESLIE TS DESN 1 BY	18,400	2,000	94	1,906
LESLIE TS DESN 2 J	33,000	N/A	40	32,960
WAUBAUSHENE TS	75,900	N/A	124	75,776
WOODBRIDGE TS DESN1	23,600	2,038	632	1,406
BRAMALEA TS DESN 1 B	27,200	2,500	1,620	25,580
BRAMALEA TS DESN 1 Y	32,200	1,800	710	31,490
BRAMALEA TS DESN 2 JQ*	51,600	N/A	8	0
BRAMALEA TS DESN 3 EZ*	113,800	N/A	352	0
CARDIFF TS DESN BQ	70,100	2,000	293	69,807
CHURCHILL MEADOWS TS DESN BY	60,000	5,000	3,104	56,896
COOKSVILLE TS DESN 1 JQ*	57,100	N/A	7	0
COOKSVILLE TS DESN 2 EZ	59,200	1,000	165	59,035
ERINDALE TS DESN 1 E	25,800	5,000	3,230	22,570
ERINDALE TS DESN 1 Q	21,000	5,000	2,646	18,354
ERINDALE TS DESN 2 YZ	93,600	5,000	3,592	90,008

[61] Note: N/A means that HONI did not allocate capacity or there is no capacity.

Connected Transformer Station HONI Owned	TS Thermal Capacity (kW) (Max Rating)	HONI Allocated Capacity (kW)	Total Connected DG Capacity (kW)	Estimated Remaining TS Capacity (kW)
EVERETT TS	63,800	2,000	2,685	61,115
HOLLAND TS	96,600	2,000	1,089	911
MIDHURST TS DESN1	119,400	3,500	1,820	1,680
MIDHURST TS DESN2	71,500	5,000	2,319	2,681
ERINDALE TS DESN 3 BJ	102,900	5,000	2,068	100,832
LORNE PARK TS DESN B	39,200	5,000	1,440	37,760
LORNE PARK TS DESN J	33,200	2,000	150	33,050
MEADOWVALE TS DESN EZ	129,200	5,000	2,415	126,785
OAKVILLE TS DESN E*	53,100	N/A	0	0
OAKVILLE TS DESN Z	49,400	1,000	645	48,755
RICHVIEW TS DESN 3 BY*	64,200	N/A	0	0
RICHVIEW TS DESN 2 Q*	44,100	N/A	0	0
TOMKEN TS DESN 1 BY	101,200	7,000	6,234	94,966
TOMKEN TS DESN 1 EZ	102,600	5,000	3,192	99,408
WOODBRIDGE TS DESN 1* EQ	10,300	N/A	31	0
MOWHAWK TS B1	11,700	1,000	487	11,213
MOWHAWK TS Y1	8,900	1,000	1,166	7,734
LAKE TS DESN 1*	57,100	N/A	16	0
LAKE TS DESN 2 J1J2	7,400	2,700	954	6,446
LAKE TS DESN 2 Q1Q2	8,900	3,450	995	7,905
NEWTON TS*	14,200	525	705	0
DUNDAS TS BY	69,600	1,000	456	69,144
DUNDAS TS JQ	51,800	5,000	2,218	49,582
NEBO TS DESN 1 B	41,500	1,000	400	41,100
NEBO TS DESN 1 Y	41,500	1,000	668	40,832
NEBO TS DESN 2 JQ	15,000	5,000	2,238	12,762
HORNING TS B1B2	10,600	1,000	608	9,992
HORNING TS Q1Q2	2,500	1,000	1,334	1,166
ELGIN TS DESN 1 DK*	6,800	N/A	16	0
ELGIN TS DESN 1 JQ	10,900	1,000	98	10,802
ELGIN TS DESN 2 EZ*	30,100	N/A	0	0

Connected Transformer Station HONI Owned	**TS Thermal Capacity (kW) (Max Rating)**	**HONI Allocated Capacity (kW)**	**Total Connected DG Capacity (kW)**	**Estimated Remaining TS Capacity (kW)**
EVERETT TS	63,800	2,000	2,685	61,115
HOLLAND TS	96,600	2,000	1,089	911
MIDHURST TS DESN1	119,400	3,500	1,820	1,680
MIDHURST TS DESN2	71,500	5,000	2,319	2,681
GAGE TS DESN 2*	33,900	N/A	0	0
GAGE TS DESN 3*	30,700	N/A	0	0
GAGE TS DESN 4*	79,700	N/A	0	0
BEACH TS DESN 1 B1B2*	400	N/A	0	0
BEACH TS DESN 1 Y1Y2*	6,700	N/A	66	0
BEACH TS DESN 2 J1J2	9,200	1,000	557	8,643
BEACH TS DESN 2 Q1Q2	8,200	5,000	723	7,477
STIRTON TS BY	11,800	1,000	344	11,456
STIRTON TS QZ	9,000	0	166	8,834
KENILWORTH TS DESN 1*	10,600	0	0	0
KENILWORTH TS DESN 2	26,600	0	0	26,600
BURLINGTON TS	94,500	0	0	94,500
BIRMINGHAM TS DESN 1 BY	5,000	0	0	5,000
BIRMINGHAM TS DESN 1 JQ	5,000	550	263	4,737
BIRMINGHAM TS DESN 2 DK	37,200	0	0	37,200
BIRMINGHAM TS DESN 2 EZ	15,000	0	0	15,000
WINONA TS	53,300	5,000	1,966	51,334
BUNTING TS J1J2	6,300	0	0	6,300
BUNTING TS Q1Q2	6,300	1,000	1,261	5,039
CARLTON TS DESN 1 EQ	18,100	0	41	18,059
CARLTON TS DESN 2 BY	23,600	1,125	890	22,710
CARLTON TS DESN 2 HK	26,800	1,000	745	26,055
GLENDALE TS BJ	6,400	1,000	0	6,400
GLENDALE TS DQ	9,000	2,000	666	8,334
GLENDALE TS DESN 2 EY	10,900	0	0	10,900
VANSICKLE TS BY	23,700	1,000	406	23,294
VANSICKLE TS JQ	15,800	3,000	1,028	14,772
BRAMALEA TS DESN 1 B	27,200	2,250	650	26,550

Connected Transformer Station HONI Owned	**TS Thermal Capacity (kW) (Max Rating)**	**HONI Allocated Capacity (kW)**	**Total Connected DG Capacity (kW)**	**Estimated Remaining TS Capacity (kW)**
EVERETT TS	63,800	2,000	2,685	61,115
HOLLAND TS	96,600	2,000	1,089	911
MIDHURST TS DESN1	119,400	3,500	1,820	1,680
MIDHURST TS DESN2	71,500	5,000	2,319	2,681
BRAMALEA TS DESN 1 Y	32,200	10,000	5,288	26,912
GOREWAY TS DESN 1 B	50,100	10,000	5,867	44,233
GOREWAY TS DESN 1 Y	51,400	10,000	4,597	46,803
GOREWAY TS DESN 2 J	25,000	5,000	3,404	21,596
GOREWAY TS DESN 2 Q	25,000	5,000	0	25,000
PLEASANT TS DESN 1 JQ	100,900	1,700	976	99,924
PLEASANT TS DESN 2 BY	37,200	10,000	4,668	32,532
PLEASANT TS DESN 2 EZ	51,700	5,000	5,478	46,222
PLEASANT TS DESN 3 F	27,700	5,000	1,257	26,443
PLEASANT TS DESN 3 V	28,600	5,000	2,041	26,559
CAMPBBELL TS – DESN1, BY	61,400	3,000	11,321	50,079
CAMPBELL TS – DESN 1, JQ	63,300	5,000	3,790	59,510
CAMPBELL TS – DESN 2, ZE Bus	15,000	4,000	4,492	10,508
CEDAR TS – DESN 1, BY	17,300	1,000	1,300	16,000
CEDAR TS – DESN 1, ZE	6,400	0	827	5,573
CEDAR TS – DESN 2, JQ	35,300	0	1,425	33,875
HANLON TS – BY	29,600	5,000	7,523	22,077
			Maximum Capacity (kW)	2,500,480

- Stations with short circuit limitations.

5.3.4.3 SYSTEM CAPACITY CONSTRAINTS

Capacity constraints for connecting REG facilities exist at the following HONI owned stations due to short circuit limitation.

1. Kleinburg TS
2. Cooksville TS DESN 1

3. Oakville TS DESN E
4. Richview TS DESN 2 and 3
5. Woodbridge DESN 1
6. Lake TS DESN 1
7. Newton TS
8. Gage DESN 2,3 and 4
9. Elgin TS DESN1, 2
10. Beach TS DESN 1
11. Kenilworth TS DESN 1
12. Bramalea DESN 2 and 3

Alectra Utilities has not experienced feeder level constraints in connecting REG projects. However, potential constraints include insufficient individual padmount or pole-mount transformer capacity, or increased customer-side voltage due to the number of DG connections. These potential constraints are not expected to materialize unless the utility experiences an unexpectedly high level of REG penetration in the future. As such, subject to the above-noted TS capacity constraints and risk of unforeseen distribution system constraints, there is sufficient capacity in place to connect REG projects based on the utility's current forecasts.

5.3.4.4 INVESTMENTS IN SYSTEM CAPABILITY TO ACCOMMODATE REG CONNECTIONS

Based on its 2020-2024 forecast for REG connections, Alectra Utilities expects no feeder or station constraints other than at certain HONI stations (as specified above). There is potential capacity to connect an additional 3.2 GW of REG (662 MW on Alectra Utilities-owned TSs and 2,500 MW on HONI-owned TSs) to Alectra Utilities' distribution system. Based on the relatively limited volume of REG connections forecasted for the 2020-2024 period, Alectra Utilities does not foresee a need to engage HONI to pursue station upgrades in order to accommodate REG connections. Where no additional REG can be connected due to capacity constraints at a specific HONI-owned station, Alectra Utilities plans to investigate and offer, if available, alternate solutions using feeders from other stations in reasonable proximity that have available capacity and at no material incremental cost.

Accordingly, Alectra Utilities has not planned any capital expenditures to fund expansions of its distribution system to accommodate REG connections during the 2020-2024 period.

5.3.4.5 GRID MODERNIZATION APPROACH

Alectra Utilities' distribution system needs to evolve so that it is prepared for a future for which it was not initially designed. The traditional distribution system design is based on large generating stations which are located away from the power consumption areas, one way flows of electricity and information, and which offer limited choices to customers in the way electricity is produced, distributed and transacted. The following are the drivers which require the electrical grid to evolve.

- Changing Electricity Supply Mix (e.g. penetration of DERs)
- Advancement in Information and Control Technologies
- Electrification of Transportation Infrastructure
- Providing New Market Opportunities for Customers
- Threats to Resilience and Reliability

Alectra Utilities' approach to grid modernization considers the above-noted drivers and attempts to solve the challenges of integrating conventional and renewable sources with energy storage, integrating electric vehicles and smart buildings, deploying condition monitoring and using real time telemetry data to gain operational efficiencies while ensuring that the grid is resilient and secure to withstand growing cybersecurity and aging challenges.

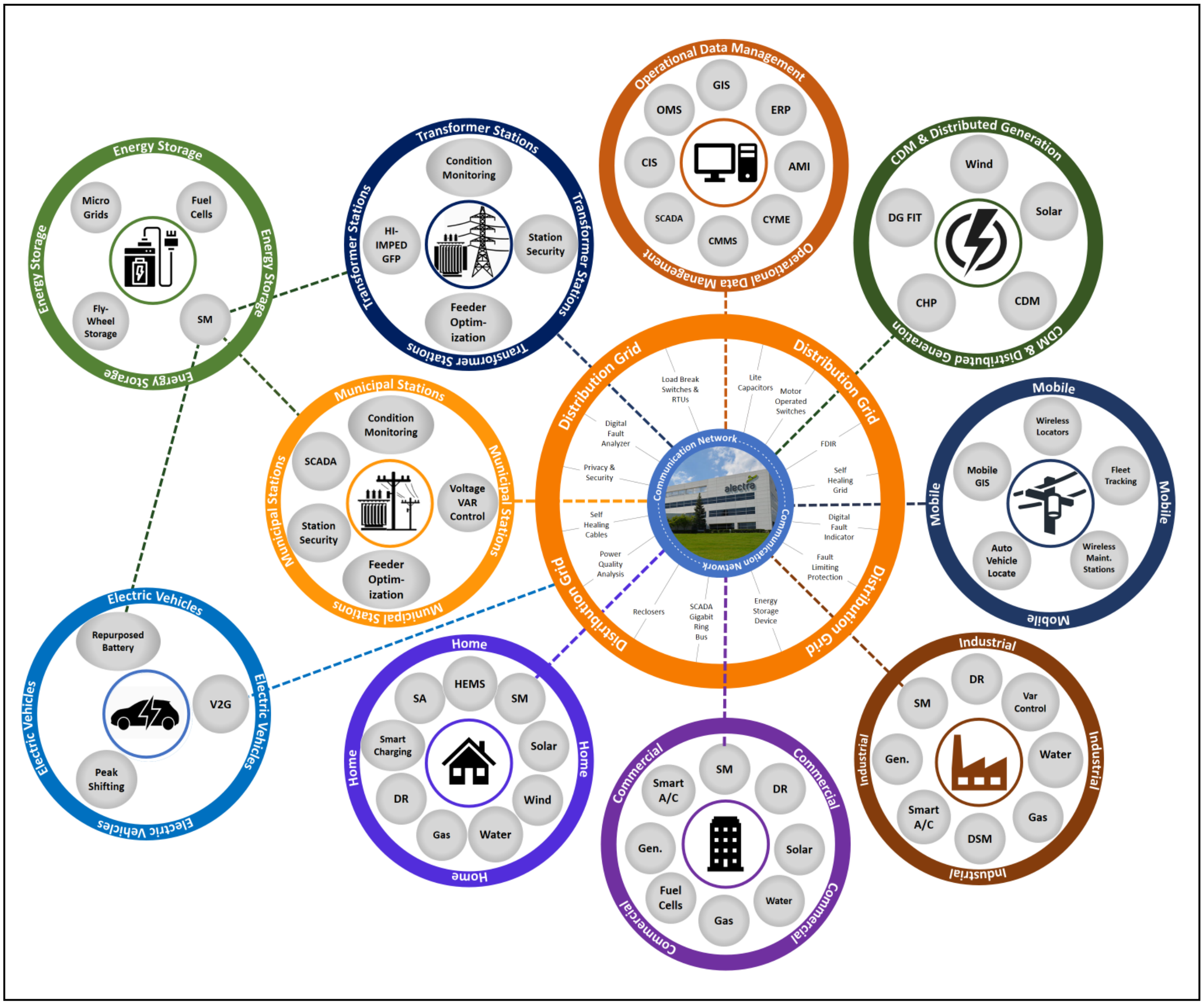
Alectra Utilities' grid modernization plans take into account the extent of grid modernization efforts made by each of its predecessor utilities and the paths they were on. The company has also sought to leverage the best practices of the predecessor utilities in developing its singular approach to grid modernization for the utility as a whole, and for managing the system to meet customer expectations for service, quality, choice, and affordability.

In some cases, this requires adopting one of the predecessor utility's technology, systems, or processes to build upon. In other cases, it requires a move to something entirely new. The company's decision framework involves considerations about pacing and sustainability of change management, maturity and inertia of existing processes and technology, best practice evolution, expected outcomes, and cost.

Grid modernization is not an end state; rather it is a process that has been occurring since the first grid was built. Every year, improvements bring more value to the grid for its customers through the introduction of new technologies, systems, and processes. Alectra Utilities operates a grid today that is highly developed with layers of information technology and operational technologies ("IT/OT"), many of which have not been traditionally considered part of the "smart grid" but which, in Alectra Utilities' view, are all part of grid modernization. Customer support systems like web portals, CIS, business decision-support systems like ERP, mobile production support systems like Automatic Vehicle Location ("AVL"), mobile GIS, Field Worker, station security systems, feeder optimization software, and others are all considered investments in grid modernization. The integration of all these advancements in IT/OT with the "foundational technologies" more traditionally considered part of todays "smart grid" like SCADA, Automated Distribution Management Systems ("ADMS"), Outage Management System ("OMS"), and smart meters, continues within Alectra Utilities with ongoing refresh.

These foundational technologies and systems are leveraged incrementally in a way that takes advantage of emerging opportunities to harness the value of DERs, energy storage, electric vehicles ("EV"s), enhanced Advanced Metering Infrastructure ("AMI"), Home Energy System ("HEMS"), condition monitoring, intelligent devices and Artificial Intelligence ("AI"). Alectra Utilities' representation of the modern grid is presented in Figure 5.3.4 - 1 below. This representation is useful to illustrate the connectedness and integration of grid components with communications and information systems, and interface boundaries with entities outside the organization.

Figure 5.3.4 - 1: Alectra Utilities' Representation of Modern Grid



Alectra Utilities' grid modernization efforts are focused on the following areas:

A. Deployment and integration of DERs.

B. Deployment of smart technologies for grid operation and status (SCADA, ADMS), metering and distribution automation to improve reliability, security and efficiency of the grid.

C. Increased use of digital information and condition monitoring to improve reliability and maximize asset life.

D. Preparing the grid for the electrification of transportation infrastructure.

E. Development and incorporation of demand response, demand-side resources, and energy-efficiency resources and measures to ensure timely information to customers and open new market opportunities for customers.
F. Ensuring that the deployed resources and grid operations are fully secure against cyber threats.

Alectra Utilities has presented investments for the next 5 years as part of this DSP so as to balance near-term system needs with its longer-term plans for grid modernization. Investments are largely in foundational systems to meet the challenges posed by the drivers, such as to advance capacity for bi-directional energy management, automated restoration, improved communication, condition monitoring, system hardware and software upgrades, and cyber security. Over these five years, as more information and results from pilots become available, Alectra Utilities will further calibrate the pace and direction of its grid modernization needs. Alectra Utilities will also use the planning period to continue to engage with stakeholders to ensure investments remain appropriate and that the grid is being modernized in keeping with system needs, policy, customer expectations, technology, and affordability.

A Deployment and Integration of DERs

DERs are technologies which include rooftop solar, energy storage, microgrids, load control, energy efficiency, and communication and control technologies — that produce, store, manage, and reduce the use of energy. They are small enough to be “distributed” all around the grid, close to customers and can make a meaningful impact in meeting load requirements in certain cases. The use of DERs has been growing and Alectra Utilities believes that resources can help make the grid more reliable, resilient, and equitable. DERs represent a shift from the traditional model of centralized energy resource control and ownership. In the new paradigm of state, community and consumer-driven investment in renewables, utility planning efforts must be revised to ensure the evolution towards a future grid that is notably different from the grid of the past. In order to avoid overbuilding the system and having assets stranded, Alectra Utilities believes that utility planning should proactively take into account current DER growth trends. On this basis, Alectra Utilities proposes to invest in developing capacity in DERs with the objective of being able to deploy such assets at scale to defer investments such as TS and MS upgrades as well as other distribution infrastructure, which would otherwise be planned to take place in the period after

2020-2024 Further information on this investment is provided in Appendix A13 - Stations Capacity.

DER Integration investments are required to implement pilot projects, which will enable Alectra Utilities' to develop its capability to monitor, control and optimize the integration of DERs onto its distribution system. It will enable Alectra Utilities to build capabilities that could predict the grid operational impacts of DERs, help mitigate power quality issues associated with DERs and reduce peak demand. These capabilities will be built as part of the overall DER Control Platform, also known as Distributed Energy Resource Management System ("DERMS"), further enabling a Virtual Power Plant ("VPP") with integrated controls and real time signals in order to operationalize DERs as an aggregated source of capacity and storage.

For further information please refer to Appendix A16 - Distributed Energy Resources (DER) Integration.

B Deployment of Smart Grid Technologies for Grid Operations, Metering and Reliability

B.1 Grid Operational Technologies

Continuity of service including restoration will be supported through intelligent sensors, systems, data management and automated switches for sectionalizing and self-healing in Fault Detection, Isolation and Recovery ("FDIR"), and Automatic Feeder Restoration ("AFR") schemes, Advanced Metering Infrastructure ("AMI"), automated voltage control, dynamic volt/var compensation, and dispatchable storage to support power quality.

As the central hub of real-time control and telemetry, Alectra Utilities' control room represents the critical nerve center for the entire utility. During fault events, power system controllers will utilize systems such as the ADMS to perform switching, isolation and restoration activities, and the OMS to record operational and reliability data associated with the event. Further, SCADA systems are used to facilitate the real-time communications of telemetry data, such as asset status (e.g. open or closed switch), loading, current and voltage levels, as well as real-time operational control of SCADA-enabled assets, such as stations circuit breakers and distribution gang-operated load-break switches. Further details on these investments are provided in Appendix A11 - SCADA and Automation.

B.2 Distribution Automation

Alectra Utilities is planning several investments that are designed to add fault indication, distribution automation, and upgrade the associated communication infrastructure. These include:

- Distribution Automation
- Fault Indication
- Communication Infrastructure

These three investments are interrelated because communication infrastructure is required to leverage feeder automation and fault indication. They also provide better customer service due to quicker fault finding.

Distribution Automation (“DA”) introduces a number of critical advantages across the system, including the ability to perform all sectionalizing, isolation and restoration activities automatically and typically under one minute. DA also provides the ability to reduce outages to momentary interruptions for customers serviced by the segments of the feeder energized after isolating the faulted segment section of the feeder.

Based on voltage level, average feeder loading and restoration times and customer outage cost, Alectra Utilities has calculated the quantity of automated devices (overhead and underground) that can be installed on each feeder. Alectra Utilities has determined that it can support the investment of 7 devices per feeder on the 27.6/44kV system, and 4 devices per feeder on the 13.8kV system. While these values can be supported, they are based on averages. From the initial customer survey, Alectra Utilities determined that its customers prefer that the company install automated devices during renewal activities. Therefore, considering that one of the automated devices will be a tie switch, the company is targeting 3.5 devices per feeder on its 27.6/44kV system and 2.5 devices per feeder on its 13.8kV system. Similar analysis was completed for other voltage levels to determine the appropriate number of devices to target.

Table 5.3.4 - 5: Automated Devices Summary

Voltage Level	No of Feeders	SCADA Enabled Devices	Devices per Feeder	% Progress
44 kV	99	138	3.5	40%
27.6 kV	290	659	3.5	65%
13.8 kV	701	239	2.5	14%
8.32 kV	16	7	2.5	18%
4.16 kV	300	28	2	5%
Total	1,406	1,071		29%

Table 5.3.4 - 5 provides an overview of the penetration of DA devices at Alectra Utilities as of December 2018. The highest level of automation is on the 27.6kV system, which also services the largest portion of customers per feeder. Fault Indication investments are also included and appropriate as they allow for quicker fault finding and, by consequence, restoration from failures. Lastly, communication as between the multitude of devices, be it automated switches or fault indicators, requires a communications backbone. Alectra Utilities has proposed several investments necessary to leverage automation and self-healing initiatives. Further details on these investments are provided in Appendix A11- SCADA and Automation.

C Increased use of digital information and condition monitoring to improve reliability and maximize asset life

Alectra Utilities plans to leverage the results of real time telemetry data and install condition monitoring equipment primarily on stations assets with the expectation that this enhanced visibility on the condition of these assets will help to maximize their asset life.

C.1 Installation of Condition Monitoring

Alectra Utilities plans to deploy assets and technologies to obtain real-time telemetry data from both distribution and substation equipment. Real-time telemetry, such as online DGA monitoring, oil levels and temperature, allow the utility to proactively manage the performance of these substation assets through maintenance activities, and can ultimately be used to indicate when rebuilds or full replacements must be performed. By deploying condition monitoring equipment and increasing the availability of more extensive, real-time data, Alectra Utilities will be further able to maximize asset life and reduce system renewal expense. Further details on these investments are found in Appendix A14 - System Control, Communications and Performance.

C.2 Real Time Telemetry Data and Communication

During the DSP period, Alectra Utilities plans to invest in communications equipment that connects the utility's substations and distribution system equipment. This equipment allows the company to control distribution equipment that is connected by the SCADA system.

Alectra Utilities plans to invest primarily in two communications systems, as follows:

- WiMAX Infrastructure**:** Alectra Utilities will install WiMAX communication hubs in order to enable high-speed broadband communications support for overhead reclosers, SCADA-enabled padmounted switches, FIT monitoring data concentrators and ethernet-enabled revenue meters. It also plans to update existing communications systems at municipal substations to the WiMAX standard, thus providing improved communication support for substation equipment.
- Fibre Optic Infrastructure**:** Alectra Utilities plans to invest in two forms of fiber optic communications systems: (i) backup fibre optic lines to provide redundancy should one communications path fail, and (ii) replacement of obsolete and deteriorated connection points in the fibre optic network (called "SONET nodes") with modern-standard nodes.

Further details on these investments are provided in Appendix A14 - System Control Communication and Performance.

D Electrification of Transportation Infrastructure

In the long term, it is reasonable to expect that transportation will shift from its dependency on the internal combustion engine to electric power. However, the pace of this shift will be dictated by many factors such as pricing, range and incentives. Public transportation is expected to start this shift soon, but will take time to mature as fleet assets are replaced over time.

Alectra Utilities' "Drive – Workplace" initiative is driven by the following factors:

- Exponential growth in electric vehicle (EV) adoption combined with increasing quantity and value of electric vehicles from global automakers.
- Workplaces being challenged (e.g. building code efficiency requirements, visiting customers and employees seeking charging stations) to serve this new and unfamiliar market with limited understanding of the technology.
- Facilities large enough to host this type of EV charging service and responsible for electricity demand charges also being large enough to have other load demands (e.g. Heating, Ventilation and Air Conditioning equipment) which can be temporarily reduced to balance between EV and building loads.

According to the IESO's 2016 Ontario Planning Outlook[62], while EVs are expected to have only a modest impact on the quantity of electricity consumed in Ontario (i.e. 1-5% increase by 2035), their impact on peak demand is more impactful at the distribution level due to their ability to consume relatively large amounts of power for a short period of time while they are charging. The draw from EVs can be either a negative or a positive impact on the electricity grid, depending on how their consumption is matched to the availability of capacity, and how it can be increased or decreased as capacity availability changes. This workplace EV charging project seeks to pilot technologies and business models that will allow Alectra Utilities to coordinate DER uptake and operation and avoid these impacts – without requiring expensive enhancements to the distribution network. Details on the investment are further provided in Appendix A12 – Lines Capacity.

E New Market Opportunities for Customers

Supply and demand management will involve customers using the grid in ways that facilitate the efficient matching of supply and demand, taking account of available generation, storage, pricing signals, rate options, incentives and available technologies, including microgrids, HEMS, and grid/customer interface controllers. Mechanisms for coordinating with the IESO at terminal stations and providing visibility and dispatch capabilities across station assets will likely be part of this future view. The following are the projects that Alectra Utilities plans to implement to further this initiative. These projects are pilots that will provide results which the company intends to leverage for deployment on a larger scale.

[62] http://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Ontario-Planning-Outlook

This project will involve the development of a software platform to provide real-time transparency, tracking, and management of Distributed Energy Resources (DERs) providing energy services to the distribution grid. Alectra Utilities will gather real-world data on this new distribution system model by evolving the existing Power.House initiative.

Through the platform, Alectra Utilities will issue requests for the Power.House customer systems to provide distribution market services where each aspect of market participation will be transacted through and recorded transparently in real-time by the platform. These transactions will provide end-to-end visibility on customer usage and DER participation patterns. By analyzing these patterns, Alectra Utilities can prove to be a highly effective broker between understanding customer usage and changing customer behavior, consequently providing tangible incentivized benefits.

Therefore, the pilot project is a pre-requisite for the widespread adoption and utilization of DERs, and includes the following benefits:

- Developing efficient procurement processes around customers and utilities
- Enabling real-time smart contracting capabilities binding the provider and the customer through contractual obligations
- Providing real-time and efficient financial settlement processes to improve customer trust and engagement leading to higher customer value
- Securing compliance obligations through a set of highly measurable and transparent verification processes around energy transactions/incentivization between customers and utilities
- Enabling Alectra Utilities to defer or avoid investment in distribution infrastructure by leveraging the value of widespread adoption of DERs
- Minimizing the negative impact of DERs on the operation of the distribution grid

Further details on this investment are provided in Appendix A16 – Distributed Energy Resources (DER) Integration.

E.1 Data Analytics

The goal of this project is to identify which facilities/customers should be targeted for deployment of DERs, such as solar and storage assets, smart thermostats, connected home equipment and

EVs. Alectra Utilities proposes to provide data from its existing data sources, along with data from its data platform provider and 3rd parties, which will then be assessed, integrated and analyzed to identify:

- Which areas (feeders, transformers) would benefit the most from the deployment of DERs through the deferral of system upgrades or repairs
- Model the impacts of customer uptake of DERs on grid operations against a variety of different scenarios to inform utility planning and customer engagement strategies
- Identify which customers are the most likely to be able to support the deployment of DERs from a technical (roof size, orientation) perspective
- Perform research to understand the customer barriers (administrative processes) and characteristics (demographic, economic)

In a sense, this project will provide an achievable potential study for DERs, along with recommendations for how to obtain these resources. This will allow these resources to be more fully integrated into utility planning processes and provide an actionable plan for how to pursue the acquisition of these resources to defer traditional wires infrastructure. The details of this investment are provided in Appendix A18 – Information Technology Systems.

E.2 Customer Engagement and Access

In addition to traditional face-to-face, phone, survey, web portals and basic mobile apps, customers will be able to make choices about their energy mix, energy use, generation, storage and use preferences based on their needs and preferences through home interface controllers at the component level. Alectra Utilities has proposed investments in aligning websites and the creation of a Customer Self Service Portal. This provides customers the ability to access information and further supports alignment of the LDC with the objective of being an ally for customers who also seek to modernize their preferences.

F Ensure that the deployed resources and grid operations are fully secure against cyber threats

On March 15, 2018, the OEB issued a directive requiring licensed electricity transmitters and distributors in Ontario to use an industry-developed Ontario Cyber Security Framework to report on their cybersecurity and privacy readiness and maturity. Alectra Utilities' program is designed to enhance the hardware and software infrastructure within the company in order to meet the requirements of the Ontario Cyber Security Framework. The investment includes the replacement of and upgrades to Alectra Utilities' telecommunications and control technologies that are essential to system control and operations, as well as the implementation of cyber-security frameworks and solutions across the organization to provide enhanced protections and risk mitigation against cyber-security threats (including cyber terrorism). The details of this investment are provided in Appendix A18 – Information Technology Systems.

5.4.1 CAPITAL INVESTMENT PLANNING PROCESS OVERVIEW

5.4.1.1 OVERVIEW

Alectra Utilities' 2020-2024 Capital Investment Plan is the output of the utility's outcomes-orientated, customer-focused Asset Management Process. As described in detail in Section 5.3.1, Alectra Utilities developed its Asset Management Process based on the best practices of its predecessor utilities. The result is a harmonized, uniform and systematic process through which the company is able to collect, assess, evaluate, prioritize and optimize system and operational needs based on current and future operating conditions. On this basis, Alectra Utilities is able to ensure that all system and operational needs are considered across its service territory, in alignment with all relevant considerations, including customer preferences and priorities, regional planning requirements, public policy objectives, and the company's Corporate Strategic Objectives.

Through the investment planning process, Alectra Utilities establishes an investment portfolio that reflects the considerations noted above. The investment planning process that ultimately led to the investment levels set out in the 2020-2024 Capital Investment Plan were optimized using the CopperLeaf C55 system. This approach provides a uniform approach to the analysis and verification of Alectra Utilities' diverse capital needs. CopperLeaf C55 is an industry-leading solution that provides the capability to optimize capital investments on the basis of multiple variables. Alectra Utilities has been able to develop multiple investment scenarios to consider financial, risk and resource-driven constraints while ensuring capital investments are aligned with its Corporate Strategic Objectives, public policy objectives, and customer needs, priorities and preferences.

This section provides a detailed description of the process that Alectra Utilities has used to develop its 2020-2024 Capital Investment Plan, organized as follows:

- **Key Features of the Capital Investment Process:** Major features of Alectra Utilities' capital investment process include:
  a) the CopperLeaf C55 Value Framework, which assists the company in determining the overall value of each potential investment;

b) the Optimization Process, through which the company identifies its investment portfolio by applying appropriate criteria and investment bounds; and
c) the two-phase customer engagement process that has been a key input into the Capital Investment Plan.

- **Step-by-Step Description of the Investment Planning Process:** This section provides a systematic description of the investment planning process that was used to develop the 2020-2024 Capital Investment Plan, including the prioritization and pacing decision-making processes that Alectra Utilities used to ensure alignment with system needs and customer priorities and preferences.

5.4.1.2 KEY FEATURES OF ALECTRA UTILITIES' CAPITAL INVESTMENT PLANNING PROCESS

The three key features of the Capital Investment Planning Process are the CopperLeaf C55 Value Framework, Alectra Utilities' optimization process and its two-phased customer engagement process. In order to understand these important features, it is necessary to first provide a brief summary of the overall process. Details of the process are set out in the step-by-step description presented in the second part of this Section 5.4.1.

As described in Section 5.3.1, the capital investment planning process forms part of Alectra Utilities' harmonized Asset Management Process. During the development and harmonization of the Asset Management Framework, the company incorporated best practices from its predecessor utilities. In consideration of the utility's service area, number of customers, volume of assets, diverse capital investment needs and the size of the typical annual capital investment portfolio, Alectra Utilities identified a need to adopt and implement a Capital Investment Portfolio Management System to manage the company's numerous capital investment business cases, each of which represents a discrete potential investment need, in a systematic and uniform manner. In order to leverage the experience and expertise of its predecessor PowerStream, Alectra Utilities selected the CopperLeaf C55 software system as its preferred solution and customized it to the utility's requirements.

The CopperLeaf C55 system serves as a register for all of the company's capital project business cases and provides a means for the company to effectively manage its entire investment portfolio. It is an industry leading solution that provides, among other things, the capability to optimize capital investments on the basis of multiple variables, and the ability to run multiple investment scenarios so as to consider various risks and bounds, while taking into account corporate objectives and customer preferences and priorities.

In deploying the CopperLeaf C55 system, Alectra Utilities developed its Value Framework, which enabled it to determine a comprehensive value of each potential investment as part of the investment planning process. The investment's calculated value was then used to determine both its independent merit and its comparative standing among other potential investments, which were effectively competing for resources in a constrained optimization process. The investment portfolio optimization process is an iterative process that makes use of the capital investment portfolio optimization capability of CopperLeaf C55 alongside review by the Capital Investment Steering Committee and consideration of feedback from further customer engagement. From this, Alectra Utilities defines the set of projects and capital investments that it expects will drive the maximum value based on the Value Framework optimization criteria and bounds. The customer engagement that is carried out to inform the optimization process involves presentation of the preliminary optimized investment portfolio to customers for the purpose of obtaining input on and confirming customer preferences, based on information regarding investment trade-offs and bill impacts. This feedback is then used by the Capital Investment Steering Committee to refine and finalize the Capital Investment Plan for final review and approval. Please refer to 5.2.1.5 Customer Engagement Part D for a detailed explanation of the capital investment adjustments to reflect customer preferences.

A The Value Framework

Alectra Utilities employs a uniform, systematic and harmonized approach to collect, assess, prioritize and optimize system and operational investment needs based on current and future system operating requirements. Each potential capital investment is developed based on identified needs, which are driven by internal or external drivers or contributing influences, including customer needs and priorities. Alectra Utilities considers each potential capital investment based on a business case, which the company evaluates using the CopperLeaf C55 Value Framework.

The Value Framework is an algorithm that systematically determines the overall value of each potential investment by analyzing and scoring each potential investment's benefits, costs and risk mitigation measures, known as Value Measures. The Value Framework enables (i) identification of the criteria that deliver the greatest value to customers and the utility; (ii) alignment of the identified criteria to a common scale to compare dissimilar investments (i.e., financial and non-financial); and (iii) assessment of the value of investments using a rational economic approach.

There are several elements that can contribute to assessing the value of an investment that are built into the Value Framework, some of which are as follows:

- Improvements in Performance Measures**;**
- Customer Service Benefits;
- Risks mitigated by an investment;
- Consequences of an identified risk, were it not mitigated;
- Financial benefits such as cost savings; and
- Other elements that are expected to bring value to the organization (e.g., safety, environmental sustainment, innovation).

As explained in Section 5.1.3, Alectra Utilities has aligned the Value Framework with its Corporate Strategic Objectives, Asset Management Strategy and Enterprise Risk Management Framework to permit a quantitative, consistent and repeatable approach to optimize investments across the entire company. This produces a capital investment plan that yields maximum value for customers and the utility, is risk-informed and incorporates financial and non-financial benefits and other attributes on a common scale.

Alectra Utilities has trained internal business and project owners on the Value Framework to ensure a consistent application of the Value Measures.

Within CopperLeaf C55, each capital project is valued based on the scoring and calibration of the Value Measures, which include risk mitigation, financial benefits, impacts on Performance Measures, and costs. Table 5.4.1 - 1 below provides an overview of the Value Measure Categories and individual Value Measures that comprise the Value Framework.

Table 5.4.1 - 1: Alectra Utilities' Value Framework

Value Measure Category	Value Measure
Finance	Capital Financial Benefit
	OM&A Financial Benefit
	OM&A Costs
	Financial Risk
	IT Capacity Risk
	Project Cost
Reliability	Distribution System Capacity Risk
	Reliability Benefit
	Reliability for Spares Benefit
Safety	Safety Risk
Compliance	Compliance Risk
Customer Service	Customer Satisfaction Benefit
	Customer Service Benefit
Environment	Environmental Improvements Benefit
	Environmental Risk
Regulatory	Application Ready Organization Benefit
Public & Employee Perception	Reputational Risk
	Employee Wellness Benefit
Innovation	Technological Innovation Benefit

The following investment summaries show the benefit, cost and risk categories of the Value Measures that are presented in Table 5.4.1-1 above:

A.1 Value Measures: Benefits and Costs

- *Capital Financial Benefit* is used to measure capital savings such as labour cost savings, productivity improvements, and other capital cost savings. This variable determines whether the savings would result in a tangible future cost reduction (i.e., that can be applied to future budget), cost avoidance (i.e., potential expenditures that would be avoided as a result of the project) or productivity improvement (i.e., efficiency).

- *OM&A Financial Benefit* is similar to the Capital Financial Benefit, but is focused on OM&A expenditures.
- *OM&A Cost* is aimed at measuring any OM&A costs that would be added as a result of completing the project. It is a negative contributor to the project value and typically occurs on projects that create additional maintenance upon project completion.
- *Reliability Benefit* computes the cost of an outage to the customer, and is based on variables such as peak load lost, duration of the outage, duration for which redundancy is lost and the type of the customer affected. Additional reliability benefits are allocated to projects which affect worst performing feeders.
- *Reliability for Spares Benefit* is used to assess the impact of spare equipment on reliability.
- *Customer Satisfaction Benefit* is used to assess the impact of the project on customer satisfaction through addressing customer needs and priorities.
- *Customer Service Benefit* is used to assess the impact of a project on Service Quality Indicators such as new connections, appointments scheduled and met, telephone calls answered on time, written responses, emergency response, etc.
- *Application Ready Organization Benefit* is aimed at measuring Alectra Utilities' ability to provide comprehensive, timely and fact-based information for rate application processes.
- *Environmental Improvement Benefit* measures the positive impact on the environment. It is used to measure improvements such as the value of CO2 emission reduction and energy efficiency (MWh) savings.
- *Employee Wellness Benefit* is used to assess the improvement in employee engagement and the overall wellbeing of Alectra Utilities' employees.
- *Technological Innovation Benefit* is used to indicate that a new technology is adopted by Alectra Utilities, which provides efficiency, productivity or new learning.

A.2 Value Measures: Risk Mitigation

In developing each business case, the project owner specifies each risk corresponding to the applicable risk categories. The Risk Value Measure considers both baseline risk as well as residual risk. Baseline risks present the risk value if the project is not completed. The residual risk presents the remaining risk value if 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. For each risk, the business case project owner specifies the consequence (i.e., risk impact) as well as the probability of occurrence. The Asset Management group at Alectra Utilities held a number of workshops with internal business and project owners to explain the Value Framework and ensure a consistent application of the Value Measure risks.

The following provides a description of the Risk Value Measures that comprise the Value Framework:

- *Financial Risk* is used to represent a failure mode or an event that will have a direct financial consequence. For example, if the failure of a piece of equipment in a switchyard causes the destruction of a nearby breaker, there would be a financial risk associated with that failure whose consequence is valued at the cost of repair or replacement of the breaker.
- *IT Capacity Risk* represents the potential productivity impact of failing to meet Alectra Utilities' IT capacity needs. An example of IT capacity risk would be a network link between sites that potentially does not have the bandwidth required to support all of the users at one site.
- *Environmental Risk* is assessed based on the cost of remediation efforts to reverse any damage potentially caused.
- *Reputational Risk* represents the risk that a failure or event will reduce the level of confidence that customers or other external stakeholders have in the company.
- *Safety Risk* is used to assess the exposure of Alectra Utilities' employees or the general public to known safety hazards. If a significant safety risk that could lead to serious injury or death has been identified, then that risk must be mitigated either by a capital investment, an OM&A investment or some kind of operating restriction.

- *Distribution System Capacity Risk* is used to assess the lack of capacity in a station or a feeder to connect additional customers and meet Alectra Utilities obligation to service new customers. The following types of risk would typically fall under this category
    - Overloading of transmission station or distribution circuits;
    - Lack of required redundancy in transmission or distribution circuits; and
    - Events that lead to an under-voltage situation for some customers
- *Compliance Risk* is used to capture the impact of an event or a failure which would cause the utility to fail to comply with a legislative, regulatory, license requirement or with an applicable Alectra Utilities' corporate policy.

In developing the Value Framework, Alectra Utilities ensured that the Risk Value Measures are aligned with its Enterprise Risk Management ("ERM") Policy, particularly risk definition, categories of risk, risk impact as well as the criteria to derive the probability of likelihood. One of the primary purposes of the ERM Policy is to assist Alectra Utilities' management and its Board of Directors in managing key business risks affecting the company. Through the ERM principles, Alectra Utilities follows the ERM Framework to identify and manage the risk inherent in achieving the Corporate Strategic Objectives. Through the alignment of the ERM Framework with the Corporate Strategic Objectives, Alectra Utilities ensures that each decision made related to risk best supports the company's priorities. As such, it was important to ensure that the Risk Value Measures used in the Value Framework are aligned with Alectra Utilities' ERM Policy and Framework.

The above Risk Value Measures are combined in a Risk Matrix that identifies the levels of risk for each measure. The matrix defines the impact at each level to provide project owners with guidance on how to evaluate each risk identified for a project. These levels are consistent with the ERM Policy and Framework, as described in Section 5.3.1. The present section details the steps Alectra Utilities took to calibrate the Value Measures risks that make up the Value Framework, with Alectra Utilities' ERM Policy and Framework.

Alectra Utilities' ERM Policy applies to all staff, management and the Board of Directors. The purpose of the policy is to assist management and the Board of Directors in the management of key business risks affecting Alectra Utilities. The policy does this by outlining the ERM Principles that are to be followed and by establishing the roles and responsibilities for all levels of the organization. Alectra Utilities' ERM Principles are:

- Comprehensive, disciplined and continuous process to identify risk, analyze and consciously accept or mitigate within approved risk tolerances;
- Reflect that risk management is everyone's responsibility;
- Each functional area is expected to participate in risk assessments;
- Integration of risk assessment into major business processes to ensure consistent consideration of risks in all decision-making;
- Alectra Utilities will manage risks and ensure that awareness and acceptance of risk is evident to management and the Board of Directors;
- Open and transparent to support effective risk governance practices; and
- Continue to evolve and reflect industry best practices and the needs of the company.

In order to give effect to the ERM Principles, Alectra Utilities follows the ERM Framework by identifying and managing the risk inherent in achieving the Corporate Strategic Objectives. Through the alignment of the ERM Framework with the Corporate Strategic Objectives, Alectra Utilities endeavors to have all risk-related decisions support the company's priorities.

Alectra Utilities worked to align the Risk Value Measures used in the Value Framework with the ERM Framework, particularly risk definition, categories of risk, risk impact as well as the criteria to derive the probability of likelihood. Figure 5.4.1 - 1 provides the Risk Matrix that was incorporated in the CopperLeaf C55 application on which the Risk Value Measures were evaluated. For further details pertaining to the Value Framework, please refer to Appendix L - Alectra Value Framework Implementation Document.

Figure 5.4.1 - 1: CopperLeaf C55 Risk Matrix

Consequence Aide	None	Impact 150	Impact 500	Impact 1,500	Impact 4,500	Impact 7,500	Impact 12,500	Impact 30,000
COMPLIANCE	None: no corporate or legal requirements	**Threat:** Non-compliance resulting in receipt of an administrative order OR Non-compliance with a law or regulation resulting in a financial penalty of $150K or more	**Threat:** Corporate/Other: Corporate or other requirements (including contractual issues) where obligations would be approximately $500K. OR Non-compliance with a law or regulation resulting in a financial penalty of $500K or more	**Threat:** Municipal: Regulated (local level through Municipal by-laws) OR Non-compliance with a law or regulation resulting in a financial penalty of $1M or more	**Threat:** Non-compliance with a law or regulation resulting in a financial penalty of $3M or more	**Threat:** Federal/Provincial: Regulated (including OEB, CSA) OR Non-compliance resulting in work shut-down	**Threat:** Non-compliance resulting in a criminal conviction	**Threat:** Non-compliance resulting in suspension of license
DISTRIBUTION SYSTEM CAPACITY	**Threat:** Able to supply load without exceeding planning limits.	n/a	**Threat:** Can supply all load but temporarily exceeding planning limits	**Threat:** Can supply all load but there is sustained operation exceeding planning limits	**Threat:** Can supply all load but exceeding thermal limits	N/A	**Threat:** Unable to service a new load	N/A
SAFETY	No risk of incidents	**Threat:** Impact of event can be absorbed through routine activity Reportable incidents. Opportunity: Small operational improvements can be managed through routine activity	**Threat:** Risk of injury requiring medical attention	**Threat:** Non-life threatening Injuries requiring hospitalization	**Threat:** Impact of event required actions greater than routine activity. Reportable incident with serious but non-life threatening injuries **Opportunity:** Operational improvement provides minor or incremental improvement to day to day operations	**Threat:** A significant event which cannot be managed under routine activity Life threatening injuries **Opportunity:** Operational improvement provides sustained improvements to day-to-day operations	**Threat:** A critical event with a long recovery period which stretches plans to the limit and requires significant management effort to endure Life threatening injuries with long-term health implications **Opportunity:** Operational improvements provides significant improvements to day-to-day operations	**Threat:** A disaster with the potential to lead to the collapse of the organization Any loss of life and/or multiple serious long term health implications as a result of our actions **Opportunity:** Operational improvement provides a major innovative approach or significant rethink in terms of service delivery or operational improvement
ENIVRONMENTAL	No noticeable impacts with minor clean-up implications	Known impacts contained to the worksite such as fugitive emissions, minor spills with short term (< 1 year) clean-up implications	Known impacts contained to the worksite such as fugitive emissions, minor spills with medium term (up to 2 years) clean-up implications	Impacts with medium term (2 to 5 years) cleanup implications that are contained to the worksite.	Impacts are long term (>5 years) and are not contained on the worksite resulting in potential loss of flora, fauna and/or fish habitat. Impact significant enough to gain attention in provincial news media.	N/A	Impacts cause long term (> 20 years) damage to a water body, an environmentally/culturally sensitive receptor resulting in actual loss of flora, fauna or fish habitat. Impact significant enough to gain attention in national news media.	N/A
FINANCIAL	**Threat/Opportunity:** Immaterial financial impact	**Threat/Opportunity:** Financial impact of an event up to $300,000	**Threat/Opportunity:** Financial impact of an event $300,000 to $1,000,000	**Threat/Opportunity:** Financial impact of an event $1,000,000 to $3,000,000	**Threat/Opportunity:** Financial impact of an event $3,000,000 to $5,000,000	**Threat/Opportunity:** Financial impact of an event $5,000,000 to $10,000,000	**Threat/Opportunity:** Financial impact of an event $10,000,000 to $15,000,000	**Threat/Opportunity:** Financial impact an event over $15,000,000
REPUTATIONAL	Immaterial consequence	**Threat:** Some public embarrassment OR Minor effect on overall staff morale/public attitudes.	**Threat:** Short term local adverse media coverage	**Threat:** Negative press in more than one media **Opportunity:** Positive press in more than one media	**Threat:** Short-term negative media focus and /or significant concerns raised by one stakeholder **Opportunity:** Short-term positive media focus and/or significant recognition from one stakeholder	**Threat:** Long-term negative media focus and/or sustained concerns raised by more than one stakeholder **Opportunity:** Long –term positive media focus and/or sustained recognition raised by more than one stakeholder	**Threat:** Long-term negative and/or sustained concerns raised by more than one stakeholder. Indications of Stakeholders loss of confidence **Opportunity:** Long-term positive media focus and/or sustained recognition from more than one stakeholder, indicating stronger long term support	**Threat:** Stakeholders lose confidence in the organization in the long-term, permanent withdrawal of support by several key stakeholders **Opportunity:** Sustained recognition from the majority of stakeholders, long-term commitment for additional support
IT CAPACITY	Lack of capacity (or currency) of a system has no expected impact on Alectra's workforce.	Lack of capacity (or currency) of system that impacts significantly (e.g. >10% average decrease in productivity) for more than 10 Alectra's employees.	Lack of capacity (or currency) of system that impacts significantly (e.g. >10% average decrease in productivity) for more than 50 Alectras's employees.	Lack of capacity (or currency) of system that impacts significantly (e.g. >10% average decrease in productivity) for more than 150 Alectra's employees.	Lack of capacity (or currency) of system that impacts significantly (e.g. >10% average decrease in productivity) for more than 450 Alectra's employees.	Lack of capacity (or currency) of system that impacts significantly (e.g. >10% average decrease in productivity) for more than 750 Alectra's employees.	Lack of capacity (or currency) of an Enterprise wide system that impacts significantly (e.g. >10% average decrease in productivity) the entire Alectra's workforce.	N/A

A.3 Scoring using the Value Framework

Within the CopperLeaf C55 system, each of the Value Measures is calibrated to a common scale (1 value point approximately equal to $1,000). Consequently, within the Value Function, the polarity for each of the Value Measures is determined so that benefits add value and costs reduce value. The stream of benefits (or costs) is converted to a single value for the Value Measure, by taking the Present Value (PV) of the stream, back to the beginning of the current fiscal year. The PV calculation uses a consistent, system-defined discount rate to ensure timing of investment is appropriately computed. During the development of each business case in CopperLeaf C55, the project owner is guided through a questionnaire of value measures to input the suitable cost, benefit and risk measure that includes probability and impact. As the optimization process considers time as a constraint, the project owner provides risk measure inputs relative to time. In order to appropriately reflect the corresponding risks, the project owner identifies and adjusts where necessary the probability of the risk with time. For example, as the likelihood of a failure due to continuous deterioration of an asset increases over time, the risk measure for such an investment reflects the corresponding increase in probability over time to appropriately evaluate the risk over time and optimally pace the investment through the project value.

B Optimization Process

The objective of the optimization process is to develop a portfolio of capital investments that provides maximum value while meeting customer and organization needs, risk tolerances, and timing requirements. Optimization was carried out through an iterative process involving both the Stakeholder Review, as described in Section 5.3.1, and the capital Investment Portfolio optimization capability of CopperLeaf C55. The Capital Investment Steering Committee first reviewed the Capital Investment Register of submitted potential projects and determined the preliminary parameters to be used in the systematic optimization. This process is discussed below, under Steps 7 and 8 of the capital investment planning process. During the initial steps of the optimization process, Alectra Utilities was informed by an “Efficiency Frontier” methodology, which is a function of CopperLeaf C55 that identifies the level of capital investment that yields the highest expected value (i.e., the most economically efficient portfolio of investments).

The Efficiency Frontier methodology provided Alectra Utilities with an optimal investment range that offered the highest expected value for a defined level of risks. The outcome of the Efficiency

Frontier process informed the Capital Investment Steering Committee and guided discussion required to balance capital investment cost that drive expected investment value relative to the defined set of risks. The system optimization capability of the CopperLeaf C55 system utilizes the Value Framework to determine the optimal timing of projects to fit within the parameters set by the Capital Investment Steering Committee. As discussed in the Value Framework section above, the Value Function combines all the Value Measures (e.g., benefits, costs and risks) to compute the overall value of an investment. The overall value of an investment reflects the total value that the project can bring to Alectra Utilities and its customers, taking into account all of its financial benefits, impact on Corporate Strategic Objectives, risk mitigation and costs. The CopperLeaf C55 optimizer systematically selects the combination of start dates of projects that brings the highest total value while remaining within the specified financial optimization bounds.

C Customer Engagement

As described in section 5.2.1 and 5.3.1, Alectra Utilities engaged Innovative Research to assist in undertaking customer engagement specifically to support development of the 2020-2024 DSP. With assistance from Innovative Research, Alectra Utilities completed two customer consultations for this purpose. The first consultation took place before Alectra Utilities identified specific capital needs, and informed the identification of capital investments based on customers' needs and priorities. The second consultation assessed customers' preferences between specific investment options. The results of that second consultation directly affected the prioritization of specific investments in the DSP. Please refer to Section 5.3.1 – A.1.1 for a detailed explanation of how the results of the placemat engagement influenced Alectra Utilities set of potential investments. Please refer to 5.2.1.5 Customer Engagement Part D for a detailed explanation of the outcomes of the second phase of customer engagement and the capital investment adjustments that reflect customer preferences.

5.4.1.3 CAPITAL INVESTMENT PLANNING PROCESS

Starting in April 2018, Alectra Utilities initiated the process to develop a capital budget that underlies the 2020-2024 Capital Investment Plan by coordinating with business units across the company using the steps described below. Once the appropriate business case information was gathered, including customer needs and priorities from the first phase of customer engagement, the Asset Management group ran the investment portfolio optimization scenarios using CopperLeaf C55 software. The results of the optimization scenarios were presented to Alectra Utilities' Capital Investment Steering Committee for consideration and approval.

The Capital Investment Steering Committee is a cross functional team comprised of business unit leaders from Regulatory, Finance and Enterprise Risk Management as well as those accountable for the implementation of the capital projects and initiatives. This multi-departmental team was established to ensure the capital investment portfolio addresses factors that include rate impacts, customer needs and preferences, as well as the Corporate Strategic Objectives. Following the development of the potential investments, Alectra Utilities carried out a second phase of customer engagement with its customers to identify and confirm their priorities and preferences, which were subsequently incorporated into the 2020-2024 Capital Investment Plan.

In developing its proposed Capital Investment Plan, Alectra Utilities' goal was to maximize value to its customers and shareholders through the timely pacing and prioritization of investments in a prudent manner that considers customer preferences, rate impacts, the ability of the distribution system to enable new connections, and the ability to continue to provide existing customers with a safe and reliable supply of electricity. The following describes how Alectra Utilities pursued this goal.

<u>Step 1 – Identify Investment Needs</u>

Alectra Utilities 2020-2024 Capital Investment Process started with the identification of investment needs using a bottom-up approach. This approach is broad by design, capturing a wide range of needs, which are subsequently filtered to a more focussed set of investments in subsequent steps. As discussed in further detail in Section 5.3.1, all business units within Alectra Utilities were prompted to review external and internal drivers, as well as mutual contributing influences such as customer needs and preferences associated with their desired investments. In order to facilitate this process, Alectra Utilities held internal workshops to review the identified drivers and contributing influences. The key elements of these workshops were:

- Identification and discussion of the customer needs and priorities identified through the most recent customer engagement activities and how these influence investment selection (further discussion of this can be found in 5.3.1).

- Identification and alignment of the Corporate Strategic Objectives with the identified investment needs. The responsibility for identifying investment needs was assigned to the individual business units that were tasked with implementing and delivering the specific corporate objectives.

- Identification and discussion of the lessons learned from the previous Asset Management Process (as further described in Section 5.3.1) to ensure that continuous learning and improvement is accounted for at the initial stage.

<u>Step 2 – Categorize Investment Need by Driver</u>

Once the investment needs were identified, the business units assigned project owners and categorized the identified investments in accordance with the OEB's defined investment categories (i.e., System Access, System Renewal, System Service, and General Plant). The categorization of investments was based on investment drivers. For example, a driver for System Service projects is to support capacity delivery whereas a driver for System Renewal is to mitigate failure risks. This in turn informed the project owner of specific justification criteria required to gather the background information and appropriately assess the outcome of the investment need. For example, System Renewal investments may require specific customer outage impact information whereas system access investment might require information regarding construction plans and schedules from municipalities and developers. The identification of investment need directed the project owner to complete specific information related to that need as they moved through the next steps.

Step 3 – Identify Solutions and Determine Feasible Technical Alternatives

Once the project owner identified the need and driver, they reviewed various alternative solutions that might be available. Alectra Utilities' project owners took into consideration multiple sources of data, such as asset condition assessment results, system capacity studies, input from interdepartmental committees and cost / benefit assessments, as further described in Section 5.3.1. In considering the alternative solutions, the subject matter experts considered, among other things, conservation and demand management, as well as non-wires solutions, to assess technical feasibility, timing and ability to address the investment needs in a cost effective manner.

Step 4 – Develop Business Cases

In this stage, project owners developed business cases for each potential capital investment using the CopperLeaf C55 software. As discussed in part 2 of this DSP section 5.4.1, above, the CopperLeaf C55 system utilizes the Value Framework to guide each project owner to identify the associated investment benefits, costs, risks, and project details. For each business case, the relevant project owner completed the project details which outlined the reason for the potential investment, the alternatives considered, and the impacts to customers.

Prior to the business case development process, the Asset Management group obtained appropriate inflation and discount rates from the Finance group and inputted the rates into CopperLeaf C55. In determining the value of each potential investment, the CopperLeaf C55 system calculated the present value of the project using the discount rate.

Project details forming part of each business case included the preferred start date for the investment and the proposed in-service date, as well as the cost of the investment. The project owner inputted the risks and benefits of the project guided by the Value Measures explained above. The project owner was required to identify which Value Measure their project would address from the list identified in Table 5.3.1 – 7. Each identified benefit required completion of a questionnaire to assess the value that the benefit brings. For example, if a reliability benefit was identified, the project owner needed to identify how many failures would be avoided, the expected peak lost load, the average duration, and the customer type impacted.

During the development of business cases for system access investments, project owners considered the timing and pacing of the potential investments based on dates provided by external stakeholders, such as developers, municipalities, regions, provincial agencies, as well as Regional Planning working groups. Alectra Utilities deems system access investments to be mandatory and continuously monitors developments to adjust pacing to meet externally driven timelines. Since the timing of system access investments is beyond the control of Alectra Utilities, the pacing of System Access investments are determined by available development and construction schedules as provided to Alectra Utilities from ongoing discussions with customers, developers, road authorities, transportation agencies and Regional Planning working groups lead by IESO or HONI. For additional details pertaining to Regional Planning with third parties, please refer to Section 5.2.2.

The pacing of planned renewal investments was a key element considered during development of the system renewal business cases, where Alectra Utilities took into account the timing and pace of asset replacement. Alectra Utilities took into consideration the outcomes of the Asset Condition Assessment in the development of business case alternatives for system renewal investments. For certain system renewal investments, such as replacement of poles, underground cables and switchgear, Alectra Utilities considered the pacing of renewal so as to be responsive to identified customer needs and priorities, as well as costs, reliability, risk levels, system constraints and available resources required to execute the work. In considering alternative pacing options for other asset renewal investments, Alectra Utilities worked to establish renewal pace that addresses these factors in a manner that results in smoother, more predictable rate impacts for customers, while addressing customer priorities, risks, operational needs, and Corporate Strategic Objectives.

In considering alternatives for System Renewal business cases, Alectra Utilities considered the condition of the assets to understand the volume of end-of-life, hazardous and unsafe, very poor and poor condition assets, and then aligned the condition with system reliability performance trends and incorporated customer needs and priorities. For each planned System Renewal project and initiative, the project owner recommended a renewal pace along with alternative pacing options with corresponding benefits and risks. These alternative solutions were then used in the second phase of customer engagement to identify and confirm customer preferences once presented with cost and corresponding trade-offs (e.g., reliability, extreme weather resilience, back-up capability).

In the development of System Service business cases, project owners identified investment implementation timelines based on present system capacity levels, conservation and demand management potential and load growth forecast for each initiative. For system capacity related System Service investments, Alectra Utilities was guided by the requirements to connect new customers and ensure existing customers are not negatively impacted by expansion and development. In order to ensure sufficient capacity and appropriate system utilization levels, Alectra Utilities proposed the pacing of System Service investments based on system planning principles described in Section 5.3.1. These recommended and alternative System Service solutions were then used in the second phase of customer engagement to identify and confirm customer preferences once presented with cost and corresponding trade-offs (e.g., reliability, back-up capability, customer preference for emerging technologies/non-wires solutions).

For each risk identified, the project owner was required to identify the risk impact as well as the probability of occurrence using the Risk Matrix, which is presented in Figure 5.4.1 - 1, above. Risk Values were used to determine the level of risk mitigated by implementing the project, which was then used to compute the value for the overall project. For example, a project owner developing a business case for a new feeder construction project would have been prompted to evaluate the Distribution System Capacity risk for the specific service area considered by the project. In this example, the project owner would have evaluated the current system capacity available in the area from the system capacity study and determined that the additional projected development area would increase the loading of the system beyond the operation planning limits set by the system planning criteria. Since the load growth projection was based on the planned development, the project owner determined that that probability of the Distribution System Capacity risk for the first year was once in three years (i.e., 33%) and gradually increased in probability for year 2 and beyond to reflect that materialization of the development increases over time.

The consideration of project timing has been a key element in the development of capital project business cases because the CopperLeaf C55 system enabled the company to consider the benefit and risk of each project throughout the planning period. Selection of project pacing and timing through the CopperLeaf C55 system enabled consideration of the increasing probability of risk due to project deferral. In order to understand the impact of the increasing probability of risk due to the passage of time, Alectra Utilities assessed the changing risk profile of each project and ensured that project deferrals do not exceed the maximum constraint risk levels set in CopperLeaf C55. The setting of risk tolerance levels is discussed further in Step 8, below. Furthermore, Alectra Utilities considered the maximum timeframe that a project could be deferred to ensure deferral would not result in missed regulatory or contractual requirements, expose the organization or customers to unacceptable risk levels, and to avoid the risk of catastrophic failures.

Once a project owner incorporated all relevant project details and applicable Value Measures into the business case, he or she assessed each project alternative against the value measures and recommended the preferred solution. In determining the preferred solution, each project owner was guided by customer needs and priorities identified through the first phase of customer engagement, project value (which includes risk and benefits) and the recommended solution cost. Once the business case was completed, the project owner finalized the business case in the Copperleaf C55 system and initiated workflow for consideration and approval.

Step 5 – Approval of Business Cases

Through the Copperleaf C55 system, Alectra Utilities utilizes the system workflow function to notify and process the business case approval based on organization structure and signing authority in accordance with the company's Corporate Expenditure Authorization Policy. The approval process for a business case requires the approver to review all aspects of the investment to ensure that the investment is required and prudent to proceed for consideration. Each approver reviews the business case considering the investment need that the solution aims to address, alternative solutions considered, the rationale for the preferred solution, and the Value Measures that were used to determine the overall value of the project. Should the proposed business case not meet any of the described criteria, the business case would be rejected by the reviewer and sent back to the project owner through the authorization workflow process. Upon rejection, a project owner has the option of revising the business case recommendation, or putting the potential investment on hold for future consideration.

Step 6 – Create Capital Investment Register

Once a potential investment as described in a business case has been approved through the authorization workflow process, the CopperLeaf C55 system incorporates the business case into the CopperLeaf C55 Capital Investment Register in preparation for the portfolio optimization process. As part of the 2020-2024 Capital Investment Plan development process, Alectra Utilities approved approximately 1,200 business cases for potential capital investments, totalling approximately $2B. These business cases were transferred to the Capital Investment Register for consideration through the Optimization Process, as discussed in part 2 of this DSP section 5.4.1, above.

Step 7 – Stakeholder Review of Capital Investment Register and Optimization Strategy

The Capital Investment Steering Committee performed a review of the investments submitted for 2020-2024 in the Capital Investment Register and guided the approach to optimizing the portfolio of projects. During this review, the Capital Investment Steering Committee discussed the level of projects submitted in each investment category, the approach of grouping projects within Planning Groups, and developed optimization bounds to ensure the Capital Investment Portfolio will achieve the Corporate Strategic Objectives while taking into account identified customer needs and priorities.

Alectra Utilities developed Investment Planning Groups to identify business cases that are mandatory, in-progress, aligned to contractually agreed timelines and paced through planned renewal considerations as described above in Step 4 of this section. Optimization bounds were used to provide guidelines for the portfolio optimization and included risk tolerance or financial restrictions to ensure the optimization solution was reasonable, achievable, and prudent.

In developing the financial optimization bounds, Alectra Utilities' Capital Investment Steering Committee was informed by the application of the Efficiency Frontier methodology. As described above, the Efficiency Frontier provided Alectra Utilities with a set of optimal portfolios that offered the highest expected value for money based on investment levels, given a defined level of risk. The outcome of the Efficiency Frontier process guided the Capital Investment Steering Committee to balance the impact of cost to the expected investment value relative to defined set of risks.

Through the Efficiency Frontier tool, fifteen investment portfolio scenarios were developed at incremental investment levels starting at $200M per year up to $550M per year. Portfolio scenarios that resulted in values below the Efficiency Frontier lower boundary were considered sub-optimal because such scenarios did not result in sufficient expected value for the level of investment. Portfolios scenarios that resulted in values above the Efficiency Frontier upper boundary were also considered sub-optimal because such scenarios did not result in sufficient incremental expected value for the incremental level of investment (i.e., demonstrated diminishing returns).

Step 8 – Optimize 5 Year Investment Portfolio

The objective of the optimization process was to develop a portfolio of capital investments that provides maximum value while meeting customer and organization needs, risk tolerances and timing requirements. Optimization is an iterative process involving both Stakeholder Review, as described in 5.3.1, and the CopperLeaf C55 capital Investment portfolio optimization process. Guided by the direction of the Capital Investment Steering Committee, the Asset Management team first optimization parameters that include: i) Investment Planning Groups, ii) Optimization Bounds, and iii) Identification of Risk by Deferring Investments.

Investment Planning Groups

Alectra Utilities developed several Investment Planning Groups for use in structuring the optimization process. Investment Planning Groups were used to identify projects that are mandatory, in-progress, aligned to contractually agreed timelines and paced through planned renewal considerations as described above in Step 4, above. The use of Investment Planning Groups provided more structure to the optimization by permitting segregation of projects for optimization by the system or by holding to the starting dates identified by the project owner. A key criterion in selecting projects for planning groups was the ability for the project's start date to shift. As explained in Step 7 above, the Capital Investment Steering Committee identified five planning groups to isolate those projects with varying degrees of flexibility. With respect to prioritization, projects that were considered mandatory were automatically prioritized ahead of non-mandatory projects and projects with flexible starting or finishing dates.

The following Planning Groups were used to develop the 2020 – 2024 Capital Investment Plan:

a) **Exclude** – Projects that do not have any anticipated expenditures in the DSP 2020-2024 planning horizon.
b) **Mandatory** – 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 Progress** – Multi-year projects that are currently are under construction and require Alectra Utilities to complete. Projects may include construction of a new transmission station where pause of construction is not feasible.
d) **Innovative** – Projects include exploratory pilots with intangible benefits and learning.
e) **Annual Investment Initiatives** – Projects include renewal investments that are paced according to: asset condition; customer needs, priorities and preferences; cost; reliability; risk levels; system constraints; and available resources required to execute the work.

The Capital Investment Steering Committee reviewed the projects included in each of the above Investment Planning Groups to assess and ensure prudency.

2. Setting Optimization Bounds

In order to complete the optimization of the five-year Capital Investment Portfolio, Alectra Utilities first defined the domain of the optimization function by establishing optimization bounds that included maximum acceptable risks, maximum capital expenditure level and time bound limits to match the five-year DSP planning horizon. This section explains the process used by Alectra Utilities' Capital Investment Steering Committee to establish these optimization function bounds.

Maximum Acceptable Risks

Consistent with Alectra's Enterprise Risk Management Policy, the Capital Investment Steering Committee reviewed the CopperLeaf C55 Risk Matrix (see Figure 5.4.1 - 1) and established maximum acceptable risk levels for each Value Measure risk based on a set common scale probability of a one in ten year scenario (i.e., 10%). The Capital Investment Steering Committee evaluated each Value Measure risk and took into consideration: customer needs and priorities; Corporate Goals and Objectives; system and operational constraints; fiduciary responsibility; environmental stewardship; professional judgement; as well as public and employee safety.

Maximum Capital Expenditure

As described above, the Efficiency Frontier function in CopperLeaf C55 provided Alectra Utilities with the set of optimal portfolios that offer the highest expected value for a defined level of investment. The outcome of the Efficiency Frontier process guided the Capital Investment Steering Committee through the identification of investment levels that resulted in expected portfolio values above the Efficiency Frontier upper boundary, which established the Maximum Capital Expenditure optimization bounds.

Planning Horizon Period

The optimization bound of time was constrained to 2024, which is the final year of the DSP planning period. Projects not selected for the optimized portfolio were deferred by the CopperLeaf C55 beyond 2024.

3. Risk of Deferring Investments

The Capital Investment Steering Committee reviewed the optimized portfolio of projects and discussed the implication of projects identified by CopperLeaf C55 optimization for deferral beyond the 2024 planning period, as well as accepted projects which the optimization suggested be scheduled to an alternative implementation date. During this process, the Capital Investment Steering Committee reviewed the implications of project dependencies and risk complications of deferring investments to ensure that the staging of preceding and succeeding projects was appropriate and reflected the logical implementation of project phases. For example, Alectra Utilities required staging of feeder construction to be scheduled in coordination with the construction or upgrade of a municipal station. Although these projects were independent from the perspective of the business case and were approved by Alectra Utilities on their individual merits, the CopperLeaf C55 system is limited in its ability to map project dependencies and necessary predecessor tasks. Where the sequencing of project dependencies is required, the Asset Management team ensured such relationships between projects within the optimized portfolio were considered.

Step 8 – Customer Preferences

After completing the preliminary optimization of the Capital Investment Portfolio, Alectra Utilities completed a second round of customer engagement to identify customer preferences as between specific options in the utility's Capital Investment Plan.[63] Alectra Utilities provided customers with specific project descriptions, cost options with corresponding outcome trade-offs and bill impacts, and identified customer preferences in terms of investment levels, pacing and desired outcomes.

The results of the customer engagement processes were presented to the Capital Investment Steering Committee for consideration. Based on customer preferences and consideration of the Corporate Strategic Objectives, the Capital Investment Steering Committee provided the Asset Management team with instructions to make appropriate adjustments to the Capital Investment Portfolio. Please refer to 5.2.1.5 Customer Engagement Part D for a detailed explanation of capital investment adjustments to reflect customer preferences.

Step 9 – Finalize Capital Investment Portfolio

Once the Capital Investment Plan was accepted and endorsed by the Capital Investment Steering Committee, the Asset Management team finalized the investment portfolio and submitted it to Alectra Utilities' Executive Management Team for consideration and subsequent approval. For required adjustments to the investment portfolio based on the input from the Executive Management Team, the Asset Management team worked collaboratively with the project owners and corresponding business unit leaders to adjust the investment portfolio before resubmitting it for approval to the Executive Management Team and then the Executive Committee. Please

[63] This was a separate process from the initial customer engagement, which identified customers' needs and priorities, leading to the first step of the capital investment planning process.

refer to 5.2.1.5 Customer Engagement Part D for a detailed explanation of capital investment adjustments to reflect customer preferences.

Step 10 – Prepare the Five Year Plan

Upon approval of the Five Year Capital Investment Portfolio, Alectra Utilities finalized the Five-Year Capital Investment Portfolio for inclusion in Alectra Utilities' Five-Year Distribution System Plan, which was then submitted to Alectra Utilities' Executive Management for consideration and approval. In the event that adjustments are required to the 5 Year Capital Investment Plan based on input from the Executive Management, the Asset Management team works collaboratively with the project owners and corresponding business unit leaders to adjust the investment levels accordingly.

5.4.2 CAPITAL EXPENDITURE SUMMARY

5.4.2.1 INTRODUCTION

This section provides a snapshot of Alectra Utilities' capital expenditures over a 10-year period, including five historical years (i.e. 2015-2019) and five forecast years (i.e. 2020-2024). It also provides explanatory notes on: (i) plan versus actual variances and trends during the historical period from 2015 to 2019, and (ii) forecast versus historical expenditures by the OEB-defined investment category. This is Alectra Utilities' first Distribution System Plan as a consolidated utility. In light of this fact, it is important to note that information regarding historical expenditures of Alectra Utilities predecessor utilities and associated variances is provided in this exhibit for the sole purpose to comply with the OEB Filing Requirements (i.e. Section 5.4.2 of Chapter 2 of the Filing Requirement). The historical expenditure information that Alectra Utilities has provided should not be used to assess and compare Alectra Utilities proposed 2020-2024 capital expenditure plan. Each of Alectra Utilities' predecessor corporations was a separate and independent entity that was exercising their individual decision making through different management and Board of Directors, which were unrelated to each other. Furthermore, each of predecessor companies had their own priorities and objectives, which resulted in different capital budgets and plans. As such, no conclusions should be drawn about Alectra Utilities' proposed capital plan as a consolidate utility on the basis of historical spending.

Alectra Utilities completed and included in this section the OEB Appendices 2-AA and 2-AB, which provide a 10-year overview of capital expenditures across Alectra Utilities' various capital project groups and associated explanatory notes on Alectra Utilities' and its predecessor utilities' plan versus actual variances. Alectra Utilities provides detailed explanations for its material variances and trends at the project group level in Section 5.4.3.

5.4.2.2 PLAN VERSUS ACTUAL VARIANCES FOR 2015-2019 PERIOD

To comply with Section 5.4.2 of Chapter 2 of the OEB Filing Requirements, Alectra Utilities consolidated the actual capital expenditures from predecessor utilities plans and categorized the expenditures based on a common Alectra Utilities' grouping for the 2015-2018 historical period. The same categorization approach was completed for the plans attained from predecessor utilities' previously filed Distribution System Plans, adjusted to reflect the OEB's decision.

Table 5.4.2 - 1 below provides, on a best efforts basis, historical capital expenditures based on Alectra Utilities' predecessor utilities for 2015 and 2016 as well as for Alectra Utilities for 2017 and 2018. Alectra Utilities has provided the forecast expenditure for the 2019 bridge year. To ensure consistency with OEB approved plans, historical capital plans and actuals for the predecessor Horizon Utilities has been incorporated as in-service capital expenditure in the Alectra Utilities' consolidated plans and actuals as presented in Table 5.4.2 - 1. Alectra Utilities has not incorporated any non-distribution activities in the 10-year capital expenditures for the 2015-2024 period. All capital expenditure figures provided are net of capital contributions.

1 **Table 5.4.2 - 1: Consolidated Alectra Utilities Historical Capital Summary**

CATEGORY	2015 Actual			2016 Actual			2017 Actual			2018 Actual			2019 Bridge		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Fore-cast	Var
	$ MM		%	*$ MM*		%	*$ MM*		%	*$ MM*		%	*$ MM*		%
System Access	53.2	62.0	17%	62.4	55.6	(11%)	60.3	64.4	7%	64.0	64.2	0%	64.6	77.4	20%
System Renewal	106.3	121.8	15%	125.6	118.7	(6%)	132.3	134.7	2%	141.9	124.6	(12%)	141.7	132.1	(7%)
System Service	55.8	49.3	(12%)	46.5	44.3	(5%)	43.2	42.9	(1%)	35.6	22.5	(37%)	39.9	23.5	(41%)
General Plant	85.8	101.1	18%	37.9	21.1	(44%)	28.5	16.0	(44%)	28.2	25.0	(11%)	29.3	26.2	(11%)
TOTAL	**301.1**	**334.2**	**11%**	**272.4**	**239.7**	**(12%)**	**264.3**	**258.0**	**(2%)**	**269.7**	**236.3**	**(12%)**	**275.5**	**259.2**	**(6%)**

2

A 2015 Actual versus Planned: Consolidated Alectra Utilities

The 2015 Actual capital expenditures were $33.1MM or 11% higher than the planned expenditure of $301.1MM. The details that comprise the variance are as follow:

A.1 System Access

For the System Access investment category, net capital expenditures were higher by approximately $8.8MM than the planned expenditure. The increase was driven by higher than anticipated New Connections work in predecessor Enersource ($5.1MM) service territory as well as metering replacement program in predecessor Brampton ($5.6MM) service territory. The metering replacement program was required to replace specific commercial meters (i.e. form 16s) to address the safety risks associated with this type of meter.

A.2 System Renewal

For the System Renewal investment category, net capital expenditures were higher by approximately $15.5MM than the planned expenditure. The majority of this increase is attributable to increased work associated with the leaking transformer replacement in the predecessor Enersource ($6.5MM) service territory as well as increase in spending on overhead rebuilds ($2.9MM) to accommodate unforeseen renewal requirements not captured in the original estimate and determined during the rebuild construction. Furthermore, the predecessor PowerStream had an increase in pole fires resulting in higher reactive work ($2.8MM), and an increase in underground asset replacements due to a need for cable injection on cables that had increased failures ($1.8MM).

A.3 System Service

For the System Service investment category, net capital expenditures were lower by approximately $6.5MM than the planned expenditure. The decrease was as a result of the reduced spending on certain system service capacity expansion projects ($3.0MM) in the predecessor Enersource service territory due to a decrease in forecasted load, and delay in construction of Vaughan TS#4 ($4.8MM) in the predecessor PowerStream service territory resulting from a delay in acquiring land and obtaining associated approvals. The decrease was further offset by an increase in predecessor Guelph service territory due to deferral of Rockwood Municipal Substation (MS#1) from 2014 ($1.0MM).

A.4 General Plant

For the General Plant investment category, net capital expenditures were higher by approximately $15.3MM than the planned expenditure. The majority of this increase was related to the higher than expected CCRA payment amounts for Churchill Meadows and Cardiff ($10.5MM) and the CCRA payments amounts for Winona TS ($6.6MM).

B 2016 Actual versus Planned: Consolidated Alectra

The 2016 Actual capital expenditures were approximately $32.7MM or 12.0% lower than the planned expenditure of $272.4MM. The details that comprise the variance are as follow:

B.1 System Access

For System Access investment category, net capital expenditures were lower by approximately $6.8MM than the planned expenditure. The decrease was largely driven by delays by the YRRTC related to the implementation of the Y2 and H2 project ($7.8MM) offset by a slight increase in customer connections.

B.2 System Renewal

For System Renewal investment category, net capital expenditures spent were lower by approximately $6.9MM than the planned expenditure. This variance was in large part driven by a feeder project in the predecessor Horizon which was delayed due to HONI delays to complete their scope of the project work first ($4.1MM). The remaining variance was a result of lower expenditures on underground system renewal in the predecessor Enersource service territory ($2.5MM), cable replacement projects in predecessor Brampton service territory ($1.1MM), and Storm Hardening projects in the predecessor PowerStream service territory ($0.9MM). The decrease was further offset by higher rehabilitation projects in the predecessor Guelph service territory due to system requirements ($1.8MM).

B.3 System Service

For System Service investment category, net capital expenditures spent were lower by approximately $2.2MM than the planned expenditure. The decrease was primarily due to the predecessor PowerStream service territory deferring land purchases for planned stations as a result of the revised load information provided by developers ($3.6MM). The decrease was offset by the continuation of Rockwood MS#1 reconstruction project in the predecessor Guelph service territory ($1.2MM).

B.4 General Plant

For General Plant investment category, net capital expenditures were lower by approximately $16.8MM than the planned expenditure. The majority of this decrease was related to the deferral of Computer Hardware and Software projects (e.g., ERP system) ($11.3MM), fleet purchases ($3.8MM), and investment in buildings ($1.1MM). In light of the formation of Alectra Utilities in February 2017, certain General Plant investments that were planned by the predecessor utilities as stand-alone utilities were deferred so such investments could be evaluated, prioritized and executed by Alectra Utilities as a consolidated entity to maximize efficiency gains and value creation.

C 2017 Actual versus Planned: Consolidated Alectra

The 2017 Actual capital expenditures were approximately $6.3MM or 2.4% lower than the planned expenditure of $264.3MM. The details that comprise the variance are as follows:

C.1 System Access

For the System Access investment category, net capital expenditures were higher by approximately $4.1MM than the planned expenditures. The increase was primarily due to customer demand type projects in the predecessor Horizon service territory and Road Authority projects in the predecessor PowerStream service territory. Customer growth in the predecessor Horizon service territory increased customer connections ($2.4MM) and new expansion requests ($1.0MM). Furthermore, in the predecessor Horizon service territory, long-term load transfer purchases from HONI ($2.7MM) contributed to the higher spending. In the predecessor PowerStream service territory, road work projects were higher than planned ($7.9MM). The increase in expenditure was offset by lower than planned requests for new connections in predecessor PowerStream, Brampton, Enersource and Guelph service territories as well as lower road work than planned in the latter three predecessors ($10.0MM).

C.2 System Renewal

For System Renewal investment category, net capital expenditures were higher by approximately $2.4MM than the planned expenditure. The increase was primarily driven by higher rehabilitation replacement work in the predecessor Guelph service territory ($2.9MM) as a result of the removal of problematic and obsolete poles with integrated transformer units from the system.

C.3 General Plant

For General Plant investment category, net capital expenditures were lower by approximately $12.5MM than the planned expenditures. In light of formation of Alectra Utilities in February 2017, certain General Plant investments that were planned by the predecessor utilities as stand-alone utilities were further evaluated, prioritized to be executed by Alectra Utilities as a consolidated entity to maximize efficiency gains and value creation.

D 2018 Actual versus Planned: Consolidated Alectra

The 2018 Actual capital expenditures were $33.4MM or 12.4% lower than the planned expenditure of $269.7MM. The details that comprise the variance are as follow:

D.1 System Access

For System Access investments, net capital expenditures were consistent with the planned expenditures of $64.0MM.

D.2 System Renewal

For System Renewal investments, net capital expenditures were lower by approximately $17.3MM than the planned expenditure. This variance was largely due to the deferred projects as a result of the OEB 2018 ICM decision.

D.3 System Service

For System Service investments, net capital expenditures were lower by approximately $13.1MM than the planned expenditure. This variance was largely due to the deferred projects as a result of the OEB 2018 ICM decision.

D.4 General Plant

For General Plant category, net capital expenditures were lower by approximately $3.2MM than the planned expenditures. In light of formation of Alectra Utilities in February 2017, certain General Plant investments that were planned by the predecessor utilities as stand-alone utilities were further evaluated, prioritized to be executed by Alectra Utilities as a consolidated entity to maximize efficiency gains and value creation.

E 2019 Forecast versus Planned: Consolidated Alectra

The 2019 Forecast capital expenditures are expected to be approximately $16.3MM or 5.9% lower than the planned expenditure of $275.5MM. The details that comprise the variance are as follow:

E.1 System Access

For System Access investments, net capital expenditures are expected to be higher by approximately $12.8MM than the planned expenditures. The variance is driven by the increase in Road Authority work due to the Bathurst Street road widening project and customer connection work.

E.2 System Renewal

For System Renewal investments, net capital expenditures are expected to be lower by approximately $9.6MM than planned expenditures. In response to the OEB decision for the ICM funding request, Alectra Utilities did not receive required incremental funding to complete all planned system renewal investments.

E.3 System Service

For System Service investments, net capital expenditures are expected to be lower by approximately $16.4MM than the planned expenditure. Reduction in this area from previous plans was based on Alectra Utilities' Asset Management Process to evaluate, prioritize and pace as a consolidated utility.

E.4 General Plant

For General Plant investments, net capital expenditures are expected to be lower by approximately $3.1MM than the planned expenditures. The expenditure was reduced as the investments that were planned by the predecessor utilities as stand-alone utilities were further evaluated, prioritized to be executed by Alectra Utilities as a consolidated entity to maximize efficiency gains and value creation.

Alectra Utilities presents the Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements (OEB Appendix 2-AB) in Table 5.4.2 - 2.

Table 5.4.2 - 2: Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements (OEB Appendix 2-AB)

Appendix 2-AB

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

First year of Forecast Period: 2020

CATEGORY																Forecast Period				
	2015 Actual			2016 Actual			2017 Actual			2018 Actual			2019 Forecast			2020 Budget	2021 Budget	2022 Budget	2023 Budget	2024 Budget
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Forecast	Var					
	$ MM		%	*$ MM*		%	*$ MM*		%	*$ MM*		%	*$ MM*		%	*$ MM*				
System Access	53.2	62.0	16.5%	62.4	55.6	-11.0%	60.3	64.4	6.6%	64.0	64.2	0.2%	64.6	77.4	19.8%	66.5	66.9	63.2	67.1	70.2
System Renewal	106.3	121.8	14.6%	125.6	118.7	-5.5%	132.3	134.7	1.8%	141.9	124.6	-12.1%	141.7	132.1	-6.7%	139.0	142.0	154.0	156.1	177.2
System Service	55.8	49.3	-11.6%	46.5	44.3	-4.7%	43.2	42.9	-0.8%	35.6	22.5	-36.7%	39.9	23.5	-41.1%	38.0	36.9	36.0	42.4	37.2
General Plant	85.8	101.1	17.8%	37.9	21.1	-44.3%	28.5	16.0	-43.8%	28.2	25.0	-11.4%	29.3	26.2	-10.9%	39.4	34.4	35.1	30.2	24.7
TOTAL EXPENDITURE	301.1	334.2	11.0%	272.4	239.7	-12.0%	264.3	258.0	-2.4%	269.7	236.3	-12.4%	275.5	259.2	-5.9%	282.9	280.2	288.3	295.8	309.3
System O&M		104.4	--		108.0	--		101.9	--		99.2	--		102.6	--	103.5	104.9	106.4	108.7	110.9

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):

NOTE: Historical planned and historical actuals include in-service expenditures for the West.

Explanatory Notes on Variances (complete only if applicable)
Notes on shifts in forecast vs. historical budgets by category
Refer to DSP Section 5.4.2 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 5.4.2 on Variance analysis for between Plan vs Actuals.
Notes on Plan vs. Actual variance trends for individual expenditure categories
Refer to DSP Section 5.4.2 on Variance analysis for between Plan vs Actuals.

1

5.4.2.3 2020 – 2024 PLANNED VERSUS HISTORICAL EXPENDITURES: CONSOLIDATED ALECTRA UTILITIES

As mentioned above, to ensure consistency with OEB approved plans, historical capital data for the 2015-2019 period for Alectra Utilities' predecessor Horizon Utilities, has been presented as in-service capital additions in Table 5.4.2 – 1. For illustrative purposes, all the data presented in Table 5.4.2 – 3 to 6 below has been presented as capital expenditure for all rate zones.

A System Access

Table 5.4.2 - 3: System Access: 2015-2024 Expenditures

	Actual Expenditures ($MM)				Bridge	Planned Expenditure ($MM)				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
System Access	61.0	55.6	62.6	67.0	77.4	66.5	66.9	63.2	67.1	70.2

The net capital expenditure five year historical average from 2015 to 2019 for System Access is $64.7MM. The net capital expenditure five year forecast average from 2020 to 2024 for System Access is $66.8MM. The forecast spend per year is relatively consistent with the historical average. Increases in customer connections due to expected growth are offset by decreases in Metering and Road Authority with the completion of the ICON F project and YRRT respectively. Please refer to Section 5.4.3 for further details regarding the planned capital expenditures in System Access and associated variance explanation.

B System Renewal

Table 5.4.2 - 4: System Renewal: 2015-2024 Expenditures

	Actual Expenditures ($MM)				Bridge	Planned Expenditure ($MM)				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
System Renewal	122.5	119.1	136.0	129.5	132.1	139.0	142.0	154.0	156.1	177.2

The net capital expenditure five year historical average from 2015 to 2019 for System Renewal is $127.8MM. The net capital expenditure five year forecast average from 2020 to 2024 for System Renewal is $153.7MM. Alectra Utilities plans to increase investments in Underground Asset Replacements to address the increasing number of cable failures causing reliability performance to worsen. Please refer to Section 5.4.3 for further details regarding the planned capital expenditures in System Renewal and associated variance explanation.

C System Service

Table 5.4.2 - 5: System Service: 2015-2024 Expenditures

	Actual Expenditures ($MM)				Bridge	Planned Expenditure ($MM)				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
System Service	49.0	43.3	44.2	24.3	23.5	38.0	36.9	36.0	42.4	37.2

The net capital expenditure five year historical average from 2015 to 2019 for System Service is $36.9MM. The net capital expenditure five year forecast average from 2020 to 2024 for System Service is $38.1MM. Alectra Utilities plans to increase investments in Capacity (Lines) projects due to the need to build feeders to support the new urban growth areas in Markham and the redevelopment of Mississauga Lakeshore, Downtown Brampton and areas in downtown Hamilton. Please refer to Section 5.4.3 for further details of planned capital expenditures in System Service investments and associated variance explanation.

D General Plant

Table 5.4.2 - 6: General Plant: 2015-2024 Expenditures

	Actual Expenditures ($MM)				Bridge	Planned Expenditure ($MM)				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
General Plant	101.3	20.8	18.1	23.0	26.2	39.4	34.4	35.1	30.2	24.7

The net capital expenditure five year historical average from 2015 to 2019 for General Plant is $37.9MM. The historical average is largely driven by the CCRA payments paid out in 2015. For example, as explained in greater detail in EB-2017-0024, in accordance with the CCRA with Hydro One, Alectra Utilities' predecessor, Hydro One Brampton, was required to pay a "true-up" contribution to cover the cost differential between the load forecast and actual load serviced from the new transformer station at Pleasant TS. Payments of this nature were made in 2018 and are planned for 2020 resulting in an inconsistent trend. Given the inconsistencies in payments, Alectra Utilities excluded the CCRA payments from its annual historical average of General Plant investments in order to reflect the historical spend in this category in all other respects. As such, the annual historical average is $25.3MM from 2015 to 2019. The net capital expenditure five year forecast average from 2020 to 2024 for General Plant is $32.8MM or $30.6MM without the above mentioned CCRA payments. The increase in General Plant investments in the forecast period is driven mainly by increases in Information Technology as well as Fleet Renewal investments. The

Information Technology increase is related to the deferral of projects in historical years so such investments could be further evaluated, prioritized and executed by Alectra Utilities as a consolidated entity to maximize efficiency gains and value creation. Investments in fleet are required to increase to bring the fleet of vehicles to normal operating conditions to ensure vehicle availability to support operations in future years. Please refer to Section 5.4.3 for further details on the planned capital expenditures in General Plant investments and associated variance explanation.

In Table 5.4.2 - 7 below, Alectra Utilities provides the OEB Appendix 2-AA which capital expenditure information on a project-specific basis.

1 **Table 5.4.2 - 7: Capital Projects by Group Table (OEB Appendix 2-AA)**

Appendix 2-AA

Capital Project by Group Table

in $MM

Project Group	**2015 Actual**	**2016 Actual**	**2017 Actual**	**2018 Actual**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
MIFRS										
SYSTEM ACCESS										
Network Metering	18.1	9.4	12.2	10.8	14.3	14.8	14.3	10.2	11.6	12.2
Customer Connections	33.3	31.8	26.9	25.2	34.7	31.4	33.1	34.8	36.3	37.7
Road Authority and Transit Projects	9.6	14.4	23.5	31.0	27.9	19.7	17.3	18.2	19.2	20.3
Transmitter Related Upgrades	0.0	0.0	0.0	0.0	0.5	0.6	2.2	0.0	0.0	0.0
Total SYSTEM ACCESS	61.0	55.6	62.6	67.0	77.4	66.5	66.9	63.2	67.1	70.2
SYSTEM RENEWAL										
Overhead Asset Renewal	33.2	35.1	43.0	39.5	45.4	34.3	34.7	39.4	30.9	37.6
Reactive Capital	16.7	14.6	15.6	20.5	17.2	18.8	19.2	19.6	20.0	20.4

Rear Lot Conversion	4.0	4.6	3.4	0.0	5.1	4.8	1.2	1.2	4.2	8.5
Substation Renewal	9.6	10.6	9.1	10.4	5.0	12.8	4.4	2.8	3.2	5.5
Transformer Renewal	14.7	10.9	11.5	14.0	12.3	5.5	6.3	7.0	7.4	7.8
Underground Asset Renewal	44.3	43.3	51.8	43.6	45.5	61.1	74.5	82.2	88.5	95.5
Other System Renewal	0.0	0.0	1.6	1.5	1.6	1.7	1.7	1.8	1.9	1.9
Total SYSTEM RENEWAL	122.5	119.1	136.0	129.5	132.1	139.0	142.0	154.0	156.1	177.2
SYSTEM SERVICE										
SCADA and Automation	4.9	5.3	6.0	4.5	2.8	3.4	3.6	3.7	3.8	4.7
Capacity (Lines)	21.2	18.6	23.8	13.4	8.0	21.1	24.0	23.9	26.4	14.8
Capacity (Stations)	17.0	17.6	10.3	2.4	2.7	0.8	0.8	0.8	5.2	12.0
System Control, Communications and Performance	4.7	1.7	2.9	3.1	5.9	6.6	5.8	4.7	4.1	2.8
Safety and Security	1.2	0.1	1.2	0.9	3.2	5.4	2.0	2.0	2.0	2.0
Distributed Energy Resources (DER) Integration	0.0	0.0	0.0	0.0	0.9	0.7	0.7	0.9	0.9	0.9
Total SYSTEM SERVICE	49.0	43.3	44.2	24.3	23.5	38.0	36.9	36.0	42.4	37.2

GENERAL PLANT										
Facilities Management	11.6	4.8	5.2	1.4	3.7	4.2	2.6	2.9	4.6	3.5
Information Technology	24.8	9.2	5.0	4.8	10.2	15.1	18.2	19.8	12.3	8.4
Fleet Renewal	7.5	4.3	3.2	6.7	8.5	8.9	9.5	9.9	10.3	10.2
Connection and Cost Recovery Agreements	54.8	0.4	0.0	6.8	1.0	8.7	1.6	0.0	0.5	0.0
Sub-Total Material Projects	98.7	18.7	13.4	19.7	23.4	36.9	31.9	32.6	27.7	22.1
Miscellaneous Projects (under materiality threshold)	2.6	2.1	4.7	3.3	2.8	2.5	2.5	2.5	2.5	2.6
Total GENERAL PLANT	101.3	20.8	18.1	23.0	26.2	39.4	34.4	35.1	30.2	24.7
Total	333.8	238.8	260.9	243.8	259.2	282.9	280.2	288.3	295.8	309.3
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets *(input as negative)*										
Total	**333.8**	**238.8**	**260.9**	**243.8**	**259.2**	**282.9**	**280.2**	**288.3**	**295.8**	**309.3**

Notes:

1 As discussed in this exhibit, historical expenditures information is provided for the sole purpose to comply with the OEB Filing Requirements (i.e. Section 5.4.2 of Chapter 2 of the Filing Requirement) and should not be relied upon.

2 Capital expenditures are provided net of capital contributions.

5.4.2.4 SYSTEM O&M COSTS

Table 5.4.2 - 8: System O&M Costs 2015-2024

in $MM	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actual	Actual	Actual	Actual	Bridge	Planned	Planned	Planned	Planned	Planned
O&M	$104.4	$108.0	$101.9	$99.2	$102.6	$103.5	$104.9	$106.4	$108.7	$110.9

The 2015 and 2016 historical O&M expenditure information has been prepared for purposes of meeting the Filing Requirements by mapping these historical expenditures for the individual predecessor companies to current activities where possible. As the operational decisions and approaches underlying the 2015 and 2016 O&M expenditures were not made by Alectra Utilities but, rather, by separate corporate entities, and were based on different accounting and capitalization policies applied by those entities, that historical O&M expenditure information does not provide an appropriate basis for comparison or from which reasonable conclusions can be drawn.

The trade-offs between capital and O&M costs were considered within section 5.3.3.5 Impact of System Renewal on Maintenance. The year over year increases over the planning period are less than 2% reflecting only inflationary impacts. Overall the expectation is that the capital investment impact on O&M costs will be relatively minimal. Investments in system renewal that are designed to replace functionally obsolete, deteriorated and end-of-life assets may contributed to a gradual and modest reduction in required maintenance. Offset by the installation of increasing volumes of new assets through expansions and additions which may result in incremental O&M costs to remain compliant with the OEB’s minimum inspection requirements.

5.4.3 JUSTIFYING CAPITAL EXPENDITURES

5.4.3.1 OVERALL PLAN

A Overview

Alectra Utilities' capital expenditure plan demonstrates its measured and targeted approach to investment, which is guided by the company's strategy of prudently renewing its existing assets, investing in new assets only where necessary, investing in technology as a means to reduce the need for system expansion, and investing in new assets to meet customer and regulatory requirements. While Alectra Utilities will, over the 2020-2024 planning period, make capital investments in relation to each of the OEB's four investment categories to address its system needs and having regard to the priorities expressed by its customers, the focus during this period will be on (i) System Renewal investments to address deteriorated and failing infrastructure, as well as safety and reliability risks, and (ii) System Access investments to ensure system capacity to accommodate expected growth and new developments. Table 5.4.3 - 1 provides a summary of Alectra Utilities' planned investments over the 2020-2024 period.

Table 5.4.3 - 1: Summary of Capital Investments – 2020-2024

	Planned Expenditures ($MM)				
	2020	2021	2022	2023	2024
System Access	$66.5	$66.9	$63.2	$67.1	$70.2
System Renewal	$139.0	$142.0	$154.0	$156.1	$177.2
System Service	$38.0	$36.9	$36.0	$42.4	$37.2
General Plant	$39.4	$34.4	$35.1	$30.2	$24.7
Total	**$282.9**	**$280.2**	**$288.3**	**$295.8**	**$309.3**

This section provides

i. a summary of how historical and planned capital investments are allocated among the OEB's four investment categories (Section B),

ii. a discussion of the key investment drivers underlying the capital expenditure plan (Section C),

iii. a description of the forecast impact of investments on Alectra Utilities' O&M costs (Section D),
iv. information regarding the company's system capability assessment (Section E),
v. a summary of Alectra Utilities' approach to grid modernization (Section F), and
vi. a summary of Alectra Utilities' 2020-2024 Capital Investment Plan (Section G).

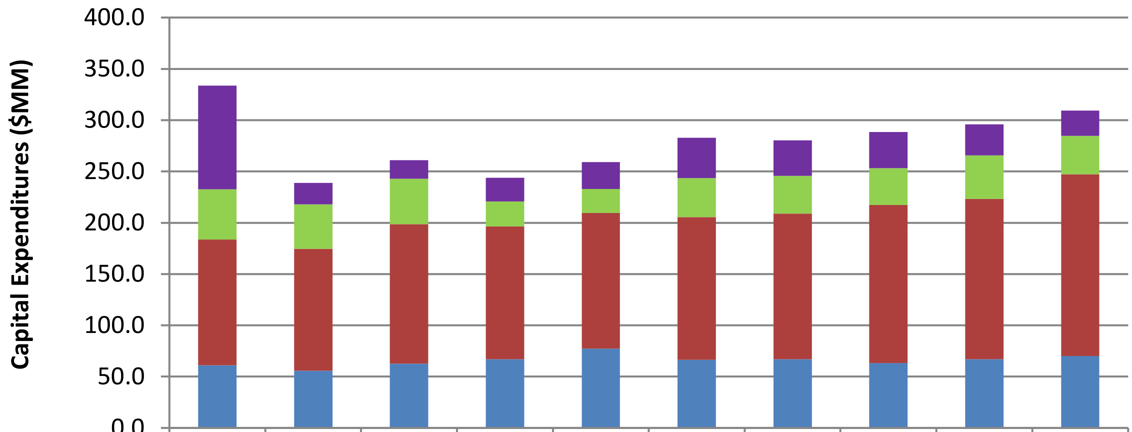
Appendix 'A' includes comprehensive Investment Summaries for each of the company's 20 project groupings. Appendix 'B' includes business cases for all projects in excess of $1MM**.**

B Historical and Planned Allocation to OEB Investment Categories[1]

Overall, Alectra Utilities is planning for a consistent level of annual capital investment, ranging from approximately $280MM to $310MM, during each year of the DSP planning period.

[1] Information regarding capital expenditures for the Historical Years is based on the capital plans of Alectra Utilities' individual predecessor utilities, which approached capital spending in a manner specific to their individual needs. The current DSP is Alectra Utilities' first, and is a comprehensive plan that takes into account and balances system needs across its entire service territory. The historical capital expenditure information has been prepared for purposes of meeting the Filing Requirements by mapping historical expenditures for the individual predecessor companies to current activities where possible. As such, the historical capital expenditure information does not provide an appropriate basis for comparison or from which reasonable conclusions can be drawn.

Figure 5.4.3 - 1: Capital Expenditures ($MM) by Investment Category (2015-2024)



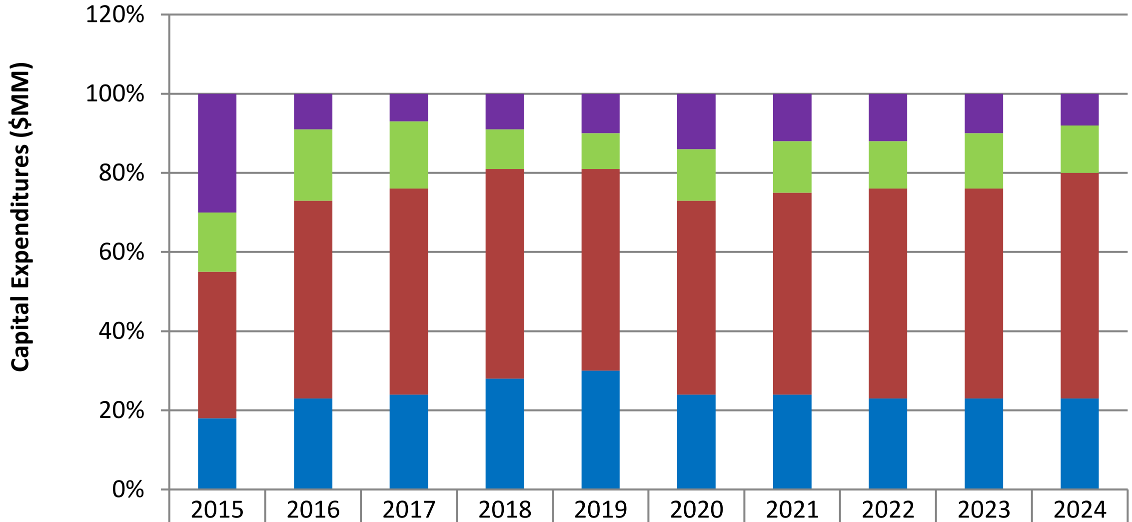
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
General Plant	101.3	20.8	18.1	23.0	26.2	39.4	34.4	35.1	30.2	24.7
System Service	49.0	43.3	44.2	24.3	23.5	38.0	36.9	36.0	42.4	37.2
System Renewal	122.5	119.1	136.0	129.5	132.1	139.0	142.0	154.0	156.1	177.2
System Access	61.0	55.6	62.6	67.0	77.4	66.5	66.9	63.2	67.1	70.2

Year

To address urgent system renewal needs, the DSP plans to gradually increase System Renewal investments (from $139.0MM in 2020 to $177.2MM in 2024) and to reduce General Plant investments (from $39.4MM in 2020 to $24.7MM in 2024), with System Access and System Service investments remaining relatively flat across the five-year DSP period. Refer to Figure 5.4.3 - 1.

Investments in System Access and System Renewal represent 73% of the total capital investment plans in 2020. This increases to approximately 80% of the total planned investments in 2024. The allocation of the overall DSP investment among the four categories is similar to the company's present allocation of its capital investments, but represents a continuation of the trend during the historical period, among Alectra Utilities and its predecessors, of increasing the proportion of overall investment that is targeted at System Renewal, while reducing the proportion of overall investment that is focused on System Service and General Plant. Please refer to Figure 5.4.3 - 2 which illustrates the percentage allocation of the DSP Investment Plan by OEB investment category.

Figure 5.4.3 - 2: Percentage of Total Portfolio by OEB Category

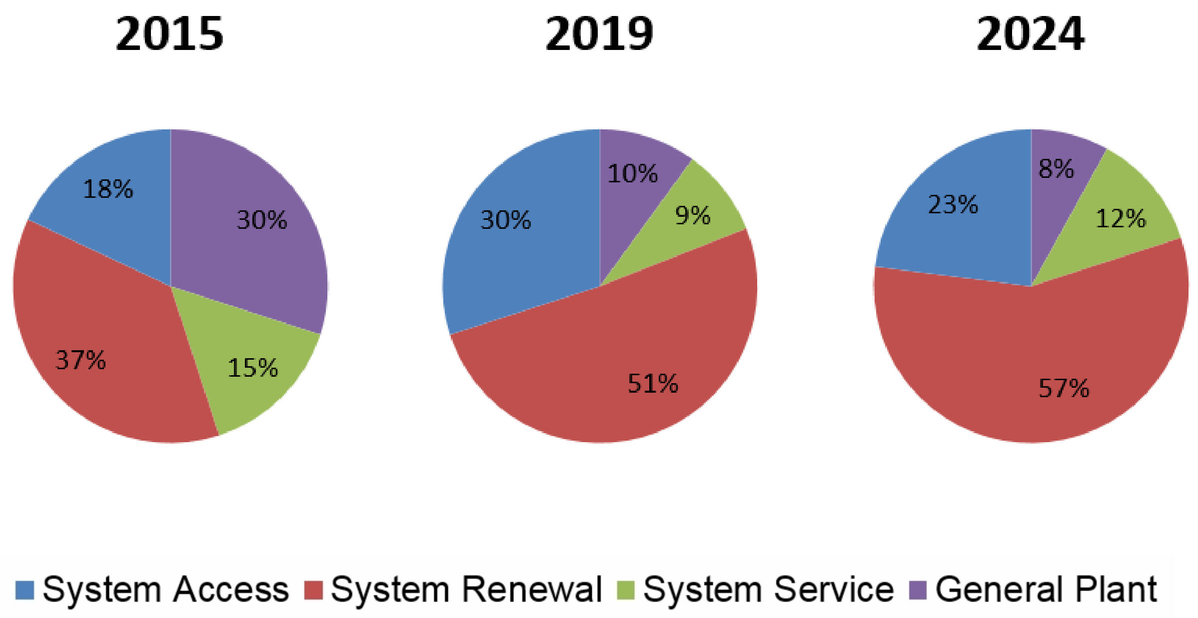


	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
General Plant	30%	9%	7%	9%	10%	14%	12%	12%	10%	8%
System Service	15%	18%	17%	10%	9%	13%	13%	12%	14%	12%
System Renewal	37%	50%	52%	53%	51%	49%	51%	53%	53%	57%
System Access	18%	23%	24%	28%	30%	24%	24%	23%	23%	23%

Year

System Access investments, which are to a significant extent beyond the company's ability to control, have generally increased during the historical period but are expected to remain relatively steady during the planning period and therefore account for a decreasing proportion to the overall level of investment over the planning period relative to historical actuals. Figure 5.4.3 - 3 illustrates investment proportions at five year increments which include the 2015 historical actuals, the 2019 bridge year and the planned 2024 investment period based on the OEB investment classifications. The graphs, presented at five year incremental periods, illustrate how predecessor utilities' and now Alectra Utilities' capital investments adjust and respond to the needs and drivers for that period.

Figure 5.4.3 - 3: Allocation of Capital Investment by OEB Category Investments (2015, 2019, 2024)



The increased focus on System Renewal investments during the DSP planning period is in response to the trend of increasing system outages experienced since 2014 by Alectra Utilities and its predecessor utilities. Excluding outages resulting from Major Event Days ("MEDs"), from 2014 to 2018 Alectra Utilities' customers experienced an 8% annual average increase in outage duration and a 6% annual average increase in outage frequency. Alectra Utilities considers this declining level of reliability to be unacceptable, and the feedback it has received through customer engagement indicates that customers strongly support renewal investments necessary to address declining system reliability. By examining its system outage causes and trends, as well as assessing the condition of its underground cables, Alectra Utilities has determined that the leading contributor to this trend is defective equipment and, in particular, the significant number of failures of underground direct-buried cable and cable accessories. Therefore, to maintain system reliability at the current five year historical average, the distribution system requires a proportional increase in System Renewal investments focused on Underground Asset Renewal, and which are particularly targeted at underground direct-buried cable and cable accessories. Consequently, over the five-year DSP planning period, the proportion of total investments that are focused on System Renewal will increase from 49% in 2020 to 57% in 2024, for an average of 53% of total expenditures over the period. Underground Asset Renewal represents approximately 52% of

System Renewal investments or 28% of total planned capital expenditures during the DSP planning period.

Alectra Utilities' level of investment in System Access varies based on customer driven demand for connections and the need to accommodate requests from road authorities to relocate and reconfigure distribution infrastructure. In 2015, System Access investments comprised 18% of the overall capital investments made by the company's predecessor utilities. This has increased to 30% as of 2019 as a result of significant investments required in road authority projects. However, this level of spending is expected to reverse and stabilize such that by 2024 approximately 23% of the overall capital investment will be attributable to System Access. The reduction of investment required by System Access over the planning period relative to the historical period is due to the completion of the H2 and Y2 projects for the York Region Rapid Transit ("YRRT") in 2019. As set out in the Manager's Summary to this DSP, Alectra Utilities has proposed to establish a variance account to record the differences between the revenue requirement impact of the utility's forecast and actual expenditures on projects driven by external requirements to relocate or remove equipment to accommodate work by road authorities or regional transit projects.

Investments in System Service, which comprised 15% of overall capital investments by the predecessor utilities in 2015, increased to 18% and 17% in 2016 and 2017 respectively and decreased in 2018 and 2019 to 10% and 9%, respectively. The deferral of specific System Service investments (e.g. lines capacity projects) in 2018 and 2019 was required to address urgent system renewal investments. While Alectra Utilities was able to manage the limited deferral of such investment in the near term, it cannot sustain reduced expenditures any further as it has an obligation under the DSC to ensure adequate capacity is available to connect new customers as well as ensure safe and reliable power to existing customers. Over the DSP planning period, required System Service investments will increase as a proportion of overall capital investment to 13% in 2020 and 2021 to meet urgent system expansion needs before reducing to 12% in 2024.

Alectra Utilities has reduced the proportion of its total investments that are focused on General Plant from 30% by its predecessor utilities in 2015 to a present level of 10%, with a plan to further reduce this to 8% in 2024. The lower proportion of General Plant investments during the five-year DSP planning period relative to historical levels is mainly related to timing and the need to settle Connection and Cost Recovery Agreements with Hydro One Networks Inc. (HONI) as per true-up anniversaries defined by the Transmission System Code.

C Drivers of Investments by Category

Alectra Utilities' DSP, and the capital expenditure plan that it supports, has been developed using new methodologies developed by the company which draw upon the best asset management and capital expenditure planning practices of its predecessor utilities. The result is a harmonized investment planning process that has been applied to the company's entire service area on a consistent basis, such that investment needs have been prioritized and planned on a utility-wide basis rather than on the basis of the individual legacy service territories.

Alectra Utilities' investment planning process ensures that local distribution system challenges are being addressed, while adopting consistent approaches to asset renewal, capacity planning, station utilization and reactive expenditures. In order to support these objectives, the company's investment planning process has been guided by the following asset management strategies:

- Invest in additions and modifications to the distribution system as required to connect new customers and maintain regulatory compliance;
- Invest in reactive repairs and replacements to the distribution system as required in response to failures or other damage;
- Invest in system automation and modernization where appropriate to increase operational efficiencies during system renewal and expansion;
- Invest in distribution system renewal in targeted asset categories, in particular underground direct-buried cable and switchgear, to mitigate declining reliability due to asset failures and outages;
- Where possible, defer investments in station or capacity expansion; and
- Where possible, defer general plant investments.

In combination with the Asset Management Objectives outlined in Section 5.3.1, Alectra Utilities applied these asset management strategies in assessing potential investments relating to each of the OEB's four investment categories. In order to ensure responsiveness to customer needs, priorities and preferences, Alectra Utilities also undertook a two-phased approach to customer engagement as described in detail in Section 5.2.1. Before the utility identified an initial range of investment options, it sought out customer needs and priorities. Based on that input and other drivers, Alectra Utilities developed a portfolio of capital investments which was presented to customers in the second phase of the consultation to obtain their preferences between certain investment options and outcomes.

Alectra Utilities identified and used the following five 'themes', each of which is discussed further below, to assist it in communicating the needs respective potential investment options to customers to attain preferences, each of which is discussed in the corresponding sub-sections below.

- C.2.1 Be responsive to anticipated system capacity needs in areas of new greenfield development as well as redevelopment and intensification;
- C.2.2 Increase the level of investment in deteriorating underground systems;
- C.2.3 Increase resilience of the overhead system to adverse weather events;
- C.2.4 Mitigate the need to rebuild or construct new stations by applying monitoring technologies, investing in environmental protection measures and feeder ties; and
- C.2.5 Take advantage of opportunities to establish additional linkages between legacy systems and balance loads across the entire service area, as well as opportunities from emerging technologies, so as to mitigate the need for system expansions.

C.1 Customer Priorities and Preferences

Please refer to Section 2.5.1.5 Customer Engagement for a detailed explanation on the how Alectra Utilities developed the DSP based on customer needs and priorities and how the organization incorporated customer preferences in the investment plans of this DSP.

C.2.1 Be responsive to anticipated system capacity needs in areas of new greenfield development as well as redevelopment and intensification

The total population in Alectra Utilities' service area is projected to increase from 3.7 million people by approximately 500,000 persons from 2016 to 2026, which reflects a growth rate of 1.5%. A disproportionate share of this population growth, along with increased employment levels, is expected to occur over the next 20 years in certain high growth areas within the company's service area, such as York Region, Brampton, and Guelph. The development that is driving this growth is increasingly challenging Alectra Utilities' capacity to connect new customers. This is because its existing distribution infrastructure in greenfield areas is insufficient to serve such new developments. In addition, Alectra Utilities faces challenges from increasing urban intensification (e.g. the Square One area of Mississauga, Vaughan Metropolitan Centre, and Brampton City Centre) and growth from redevelopment (e.g. Hamilton Downtown and Waterfront, Port Credit area in Mississauga).

Such redevelopment and intensification growth is induced by Provincial and Municipal investment in major public transit projects such as the Light Rail Transit ("LRT") developments in Mississauga and Hamilton as well as the GO Transit electrification across multiple rail corridors within Alectra Utilities' service area. In these areas, the company's existing distribution infrastructure is not able to support the growing needs that are driven by the planned intensification and redevelopment initiatives. Therefore, in order to ensure sufficient capacity to connect and serve such developments, Alectra Utilities must expand and upgrade its existing distribution system supply feeders to support new development while ensuring safe and reliable service is maintained for existing customers. Over the planning period, and guided by municipal intensification and redevelopment plans, Alectra Utilities identified capital investment needs to support imminent development plans in Downtown Mississauga, the Vaughan Metropolitan Centre, as well as redevelopment growth in Port Credit and Pier 8 in Hamilton. Furthermore, several of Alectra Utilities' feeders are currently over the planning limit and new feeders are required to ensure adequate back up capability to meet planned outage or contingency conditions. Alectra Utilities plans to construct feeders to support ongoing growth within the system and to provide distribution system redundancy for reliability benefits.

Historical System Service expenditures between 2015 and 2018, and projected expenditures in 2019, total $184.3MM. Of these expenditures, $135.0MM were related to the construction of system capacity for lines and stations necessary to connect new customers and alleviate capacity constraints. The annual average System Service expenditures during this period was $36.9MM per year. In 2018 and 2019, Alectra Utilities received partial funding for incremental capital investments, which required it to reallocate capital from System Service to System Renewal and System Access investments. Hence, the historical $36.9MM annual average System Service expenditures include the deferral of certain feeder expansion investments that were otherwise planned for 2018 and 2019, but which were deferred to enable the company to address more urgent System Renewal and System Access investments.

Alectra Utilities has been able to manage the deferral of certain System Service investments in 2018 and 2019 through the combined application of connecting new customers on existing feeders and focusing conservation and demand management programs where feasible. Such short term management tactics have limited its deferral capabilities and introduced additional risks of prolonged outages to new and existing customers. While Alectra Utilities was able to manage with limited deferral of investments in System Service investments, it cannot sustain reduced investments any further as it has an obligation under the DSP to ensure adequate capacity is available to connect new customers, as well as to ensure safe and reliable power to existing customers.

The company's capital investment needs for System Service from 2020 to 2024 total $190.5MM, which reflects an annual average expenditure of $38.1MM. As explained in Section 5.4.1, Alectra Utilities paces its project investments based on need and value. Investments in System Service are prioritized by considering customer demand for additional connections, system demand growth, system reliability and coordination with other infrastructure work (such as road authority), watermain expansion, and other utility construction. As such, the projects that the company plans to implement over the DSP planning period are scheduled based on their relative need within an optimized portfolio - not based on historical trending. For example, in 2023 Alectra Utilities plans to integrate new feeders from stations in Vaughan and Markham. Such investments are required in 2023 and drive the System Service investment for that year to $42.4MM. Since there are fewer needs for additional stations or feeder expansion work in 2024, the System Service investment for that year is reduced to $37.2MM. This enables the company to allocate capital funding to other priority investment needs and urgent projects in 2024. Details related to the investment needs, planned projects to address these needs and expected outcomes are provided in Appendix 'A', section A11 through to A16.

C.2.2 Increase the level of investment in its deteriorating underground systems

As explained in section 5.2.3, since 2014 Alectra Utilities (including its predecessor utilities) has experienced an 8% annual average increase in outage duration due to underground cable failures. In order to address this issue, Alectra Utilities plans to increase its level of investment in underground cable replacement and rehabilitation over the 2020-2024 planning period. The Asset Condition Assessment, described in Appendix D - Asset Condition Assessment – 2018, identified that 14%, or 3,156 km, of the company's cross-linked polyethylene (XLPE) or "directly-buried" cable population is in Very Poor and Poor condition. Alectra Utilities has examined its historical cable failures, including those experienced by its predecessor utilities, against the Health Index results and determined that, without addressing the deteriorated underground cables, system reliability will continue to get worse. As such, the population of Very Poor and Poor condition directly-buried underground cables needs to be replaced on an urgent basis.

In addition to replacing underground directly-buried cables, Alectra Utilities plans to extend the lives of eligible cables where practicable, using a silicone injection rehabilitation process. The combination of implementing cable replacements and carrying out cable rehabilitation using silicone injection is consistent with best utility practice. Cable rehabilitation is a lower-cost solution that can extend the life of XLPE cables without the costly and disruptive need to excavate or to replace entire cables. Where technically feasible, Alectra Utilities prioritizes cable rehabilitation over replacement. However, not all cables are eligible candidates for rehabilitation. In particular, cables that are in a significantly deteriorated state cannot be rehabilitated because they are too deteriorated to benefit from this process and have a tendency to fail despite being injected with silicone. Alectra Utilities plans to prioritize the implementation of cable injection to maximize the number of cables that can be effectively rehabilitated over the planning period. Please refer to Appendix A10 – Underground Asset Renewal for more details pertaining to the application of underground cable replacement and rehabilitation plans.

Historical System Renewal expenditures between 2015 and 2018, together with projected expenditures in 2019, total $639.2MM, which reflects annual average expenditures during the period of $127.8MM. These expenditures mainly related to the renewal of overhead, underground and station assets. Although Alectra Utilities has continued to invest in System Renewal, the trend of increasing outage durations due to defective equipment, and from underground directly buried cables and cable accessories in particular, indicates the importance for Alectra Utilities of increasing the pace of its renewal investments, focused on underground systems in particular, to mitigate this trend that the company and its customers find unacceptable. The capital investments planned for System Renewal from 2020 to 2024 total $768.4MM, with an annual average expenditure level of $153.7MM. As noted, Underground Asset Renewal accounts for approximately 52% of these System Renewal investments and thereby represents approximately 28% of total planned capital expenditures during the DSP planning period. For further details regarding Alectra Utilities' plans in respect of underground cables, please refer to the Appendix A10 -Underground Asset Renewal.

C.2.3 Increase resilience of its overhead system to adverse weather events

Since 2014, Alectra Utilities (including its predecessors) experienced a trend of increasing outage duration due to adverse weather events. As provided in Section 5.2.3, the five year trend indicates an 86% average annual increase in customer hours of interruption from adverse weather conditions, including windstorms, ice storms and freezing rain. Alectra Utilities has determined that measuring customer hours of interruption is reflective of system reliability in adverse weather events as it accounts for both the volume of customers affected as well as the duration of the outage. A significant portion of Alectra Utilities' distribution system was designed and constructed between 1970 and 1990, and did not take into account the increasing impact of adverse weather events and the associated stress that is imposed on the overhead distribution system from such events. Due to this fact, the likelihood of catastrophic failure, which requires a longer restoration period, is increasing. Without appropriate attention to this need, Alectra Utilities' system will continue to be exposed to increasing customer hours of interruption as a result of adverse weather conditions.

Alectra Utilities plans to mitigate the impacts of adverse weather events through investments in overhead system renewal, which increases the resilience of its overhead distribution system. Overhead system renewal will target a specific population of wood poles carrying four circuits, which the company has found to be particularly susceptible to catastrophic failure in adverse weather events. Over the 2020-2024 period, Alectra Utilities plans to invest in the overhead distribution system through the Overhead Asset Renewal and Rear Lot Conversion investments. These investments will increase overall system reliability and resiliency in adverse weather conditions.

For the 2015-2019 period, Alectra Utilities (including its predecessors) invested approximately $213.3MM on renewing overhead systems (including rear lot conversions), which reflects an average annual spend of $42.7MM. For the 2020-2024 period, Alectra Utilities plans to invest approximately $196.8MM on the overhead system renewal (including rear lot conversions), which reflects an average annual spend of $39.4MM. The moderate decrease in capital spending over the 2020-2024 period reflects Alectra Utilities response to its customers' need to keep rates low and prioritize investments that maintain system reliability. As a result, Alectra Utilities assessed its investment plans and determined that, while increased resilience to adverse weather events is an important contributor to reliability levels, the more pressing need for investment is with respect to the company's underground systems that are experiencing increased cable failures. While Alectra Utilities will continue to invest in its overhead system, it will do so at slightly lower levels than during the historical period. Alectra Utilities believes that the planned level of investments should provide adequate pacing of renewal in the overhead distribution system so as to appropriately balance system risks and needs in line with customer preferences.

C.2.4 Mitigate the need to rebuild or construct new stations by applying monitoring technologies, investing in environmental protection measures and feeder ties

Alectra Utilities plans to invest in and leverage emerging technologies to enable enhanced operations. Through investments in asset monitoring technologies, as well as environment containment solutions, Alectra Utilities expects to be able to defer certain station renewal investments that would otherwise be needed. Such deferrals are supported by the larger inventory of power transformers that Alectra Utilities has as a consolidated entity, relative to each of its predecessor utilities. The availability of a larger inventory of transformers enables the company to have in place, and to implement if needed, contingency plans that allow for it to continue using transformers that would typically be considered to be beyond the end of their useful life. Alectra Utilities plans to mitigate the risk of failure, and the impacts thereof, through the continuous and remote monitoring of station assets and by implementing spill containment solutions to minimize the potential environmental impacts of power transformer failure where adequate containment does not currently exist. Through the continuous monitoring of station assets, Alectra Utilities is able to practice Reliability Centered Maintenance (RCM) on these critical assets. RCM is a structured process and methodology used to extend asset life through analysis to determine optimal action based on condition and operational criteria. Together, these investment strategies and the ability to leverage its consolidated inventory of spare station equipment will enable Alectra Utilities to defer specific and more costly station renewals.

In order to mitigate outage duration in the event of station equipment failure, Alectra Utilities plans to construct and implement additional feeder ties to enable load transfers during contingency conditions. Alectra Utilities plans to invest in the installation of automated switches for strategically placed feeder ties to facilitate the expeditious transfer of affected customers in the event of station failure or loss of supply. For the 2015-2019 period, Alectra Utilities (including its predecessors) spent approximately $44.7MM on projects related to renewing station assets. For the 2020-2024 period, Alectra Utilities plans to invest approximately $28.7MM on investments associated with station renewal. The reduced level of capital investment on station renewal over the 2020-2024 period is a result of the company's investment strategy, described above, of enhancing station asset monitoring, spill containment and implementing feeder ties, supported by its ability to leverage its consolidated inventory of station spares. With the implementation of these practices, Alectra Utilities is able to focus its resources on the higher priority need for investment in its underground systems to address the increasing frequency of cable failures. Alectra Utilities believes that the planned level of and approach to station renewal investments appropriately balances risk, reliability and customer preferences to mitigate cost increases. Details related to substation renewal investment needs, planned projects to address these needs and expected outcomes are provided in the Station Renewal investment summary in Appendix A08 - Substation Renewal.

C.2.5 Establish linkages between legacy systems and examine emerging technologies so as to mitigate the need for system expansions

Alectra Utilities plans to make targeted investments in establishing additional connections between adjacent legacy systems to assist it in balancing loads more effectively, thereby enabling it to defer the need for costly system expansions. Alectra Utilities has identified specific capital investments in areas where capacity constraints or back-up capability is required, which would have historically been addressed by predecessor utilities through the construction of additional stations or feeders. Instead, these are now being addressed by Alectra Utilities through the utilization of existing assets with minimal investment for feeder extension and ties. An example is the planned extension of 27.6kV Feeder 25M9 from Jim Yarrow TS into Mississauga along Derry Road at an investment of $2.1MM (please see project 150357 in Appendix B - Material Investment Business Cases), which eliminates the need for Alectra Utilities to build a new municipal station in northern Mississauga, the cost of which was estimated at $7.5MM.

In addition to establishing linkages between predecessor utility systems, Alectra Utilities plans to develop its capability to monitor, control and optimize the integration of Distributed Energy

Resources (DERs) into the distribution system through three related pilot projects. Through these pilot projects, Alectra Utilities intends to develop the capability to optimize the operation of DERs so as to prevent power quality issues and reduce peak demand. The projects will provide valuable data, which will help improve system planning practices. Ultimately, the ability to draw upon this data and experience will enable the company to reduce peak demand, which in turn will enable it to defer more traditional and costly distribution system investment needs. The pilot projects will also advance Alectra Utilities' ability to control and monitor DERs connected to its distribution network – ensuring they are isolated from the grid to protect employees working on the network during outages – on a pilot scale before implementing such resources more broadly in the future.

The DER integration pilot projects are driven by two investment needs. First, Alectra Utilities needs to evaluate DERs as system planning alternatives. Understanding DER capabilities will enable Alectra Utilities to utilize DER deployment as a feasible non-wires solution to defer distribution and transmission infrastructure expansion. Second, as a prudent distributor Alectra Utilities is obligated to prepare its distribution system to accept and support new technologies, including the integration of electric vehicles and charging infrastructure, solar photovoltaic generators, battery storage and home automation. By undertaking these pilot projects in the near term, Alectra Utilities is preparing its distribution system to safely and reliably respond to the expected uptake of DERs and other emerging technologies in the longer term with a coordinated architecture that balances the benefits of these resources to their owners, with the costs they potentially pose on all of the company's customer-base. Without this preparation, Alectra Utilities risks supressing customer choice due to distribution system constraints, as well as experiencing reliability of supply issues as a result of intermittent, uncontrolled supply from DERs. Over the 2020 to 2024 planning period, Alectra Utilities plans to invest $4.1MM in DER integration. Please refer to Appendix A16 - Distributed Energy Resources (DER) Integration for further details about the DER.

D Forecast Impact of Investments on O&M Costs

Alectra Utilities recognizes the importance and impact of prudent asset management and capital expenditure planning in relation to the company's long term ability to contain O&M cost. The timely renewal of assets reaching end of useful life or posing significant risks to the company (e.g.

financial, safety, environmental, regulatory) is expected to create opportunities for reducing or avoiding O&M cost.

At the same time, it is important to recognize the realities and challenges associated with managing a large portfolio of deteriorating distribution assets in a fast growing service area. Customer and load growth drivers require well-planned infrastructure expansion, which will put upward pressure on O&M cost as a result of new assets being installed, inspected, and maintained. At the same time, there are needs for ongoing asset renewal and continuing enhancement and expansion of the Alectra Utilities' inspection, maintenance and data collection initiatives for existing assets. These initiatives are part of the continued evolution of the asset management practices to support more effective and rigorous decision making. This is crucial given the deteriorating condition of distribution assets, as well as the substantial amount of underground system assets in Alectra Utilities distribution system, which is generally more costly and challenging to inspect and maintain relative to overhead systems.

Nonetheless, Alectra Utilities aims to keep year-over-year changes in O&M costs within or around the level of annual inflation. As can be seen from the Table 5.4.2-2 provided in Section 5.4.2, the overall trend in the O&M budget for Alectra Utilities over the DSP period is in alignment with the aforementioned goal. In addition, Alectra Utilities seeks out opportunities for saving or avoiding O&M costs, particularly through capital investments in System Renewal and General Plant. As described below, the expected impact to O&M costs, as a result of planned capital investments, vary by each of the investment categories.

System Access

System Access investments are mandatory, non-discretionary projects initiated by customers or third parties (e.g. Municipalities, Regions, Ministry of Transportation, etc.). The projects include the following:

- New connections and subdivisions (including industrial/commercial) connections;
- Road authority projects that require the relocation of distribution system assets;
- Metering; and
- Other customer initiated work.

System Access projects can introduce new distribution assets to the system, which results in an increase of equipment requiring regular maintenance. In addition, these projects may include the expansion of the communication infrastructure and would result in increased licensing fees on an ongoing basis.

System Service

System Service investments consist of costs associated with expanding the company's distribution system and addressing capacity, reliability and safety initiatives. An increased number of assets installed on the distribution system, will result in increased maintenance requirements. In addition, these projects may include the expansion of SCADA and related communication infrastructure which would result in increased licensing fees on an ongoing basis.

System Renewal

System Renewal investments are projects and initiatives directed toward replacing or rehabilitating deteriorating infrastructure. As an asset deteriorates, the costs associated with operating the asset generally increase as inspection and maintenance activities become more frequent and onerous due to the growing probability of asset failure. However, when an asset is replaced, while maintenance is still required, it may involve less time and resources, thus resulting in lower O&M costs. In addition, as an asset ages and its condition deteriorates there is a higher likelihood of failure which may result in higher operating costs associated with emergency work required to replace faulty equipment and restore power to customers. Thus, through risk-based approaches to planning and pro-active replacement projects and initiatives, Alectra Utilities strategically renews certain assets of the distribution system over time, thereby reducing customer outages, adverse weather related failures, and avoiding additional operating costs. Please refer to section 5.3.3.5 for an explanation of the impact of capital investments on ongoing system operating and maintenance costs.

General Plant

General Plant investments are focused on IT and Information Systems, buildings, facilities, fleet, and major tools by replacing assets (e.g. fleet) that have reached the end of their useful life. This amount includes unplanned fleet repair costs, other miscellaneous building repair expenses and certain conservation initiatives to reduce operating cost or waste.

E System Capability Assessment

Based on Alectra Utilities' 2020-2024 forecast for Renewable Energy Generation, Alectra Utilities does not project any distribution system constraints to connect REGs. In order to address certain constrained HONI stations, Alectra Utilities will continue to work with customers requesting REG connections to examine alternative feeder or connections where feasible to enable connections. Accordingly, Alectra Utilities has not planned for any capital expenditure to fund expansion of its system to accommodate REG connections during the 2020-2024 DSP planning period. Please refer to section 5.3.4 for information related to the Alectra Utilities' system capability assessment.

F Grid Modernization

Alectra Utilities' approach to investing in and leveraging emerging technologies to enable operations, maintain reliability, integrate conservation and demand management as well as to accommodate and manage the impacts of distributed energy resources are explained in chapter 5.3.4.

G 2020-2024 Capital Investment Plan

Alectra Utilities' 2020-2024 Capital Investment Plan is organized in accordance with the OEB's investment categories: (1) System Access, (2) System Renewal, (3) System Service, and (4) General Plant. Table 5.4.3 - 2, below, 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 5.4.3 - 1, in the Overview section above, provides a summary of Alectra Utilities' planned investments over the 2020-2024 period.

1 **Table 5.4.3 - 2: 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	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 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.
	Functional Obsolescence	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.
General Plant	Operational Effectiveness	Optimize the operation of assets and related processes and enhance customer experience in a financially prudent manner.
	System Maintenance and 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.

2

Alectra Utilities has organized projects within each of the investment categories into investment groups based on common drivers and outcomes. Appendix 'A' contains twenty Investment Summaries that comprise Alectra Utilities' Capital Investment Plan for the 2020-2024 period. Table 5.4.3 - 3, below, lists the project investment groups by investment category, and identifies the corresponding investment summary location in Appendix 'A'. An overview of the Capital Investment Plan is provided below. As noted in the Overview, above, Appendix 'B' includes business cases for the individual projects that comprise each investment group and which are in excess of $1MM.

Table 5.4.3 - 3: Project Investment Group by Category

Investment Category	Investment Group	Investment Summary
System Access	Network Metering	Appendix A01
	Customer Connection	Appendix A02
	Road Authority and Transit Projects	Appendix A03
	Transmitter Related Upgrades	Appendix A04
System Renewal	Overhead Asset Renewal	Appendix A05
	Reactive Capital	Appendix A06
	Rear-lot Conversion	Appendix A07
	Substation Renewal	Appendix A08
	Transformer Renewal	Appendix A09
	Underground Asset Renewal	Appendix A10
System Service	SCADA and Automation	Appendix A11
	Lines Capacity	Appendix A12
	Stations Capacity	Appendix A13
	System Control, Communications and Performance	Appendix A14
	Safety and Security	Appendix A15
	Distributed Energy Resources	Appendix A16
General Plant	Facilities Management	Appendix A17
	Information Technology Systems	Appendix A18
	Transportation Equipment	Appendix A19
	Connection and Cost Recovery Agreements (CCRA)	Appendix A20

G.1 System Access

System Access investments are comprised of projects that Alectra Utilities is obligated to carry out, pursuant to its distribution license, to connect new customers and accommodate other infrastructure projects. In addition, System Access investments include the installation of metering assets pursuant to Measurement Canada and IESO requirements, the relocation of distribution system assets in accordance with requirements under the *Public Service Works on Highways Act* ("PSWHA"), as well as Transmitter Related Upgrades driven by transmission system renewals and upgrades identified as part of regional planning initiatives described in Section 5.2.2. The planned System Access investments for the 2020-2024 period are set out in Table 5.4.3 - 4 below.

Table 5.4.3 - 4: System Access Investments (2020-2024)

	Planned Expenditures ($MM)				
System Access	**2020**	**2021**	**2022**	**2023**	**2024**
Network Metering	$14.8	$14.3	$10.2	$11.6	$12.2
Customer Connections	$31.4	$33.1	$34.8	$36.3	$37.7
Road Authority and Transit Projects	$19.7	$17.3	$18.2	$19.2	$20.3
Transmitter Related Upgrades	$0.6	$2.2	$0.0	$0.0	$0.0
Total	**$66.5**	**$66.9**	**$63.2**	**$67.1**	**$70.2**

Alectra Utilities' planned System Access investments enable it to fulfill its responsibility to continuously meet its service obligations, include for the safe, reliable and prompt connection of customers and for accurately metering and billing customers. The pacing of System Access investments in the Capital Investment Plan is primarily driven by the company's projected connection and road authority demands. Individual projects within System Access investment category, described below, have been identified and planned in a manner consistent with the guiding investment principles, particularly with respect to the objective of investing in system additions and modifications where necessary to connect new customers and to ensure compliance with distribution license obligations.

1 G.1.1 Network Metering

Overview	Alectra Utilities manages meters, meter data communications and processing systems, as well as meter testing facilities and equipment that serve approximately 991,000 customer accounts and 215 wholesale metering points. Investments in metering focus on metering equipment serving (i) distribution customers, (ii) wholesale metering points that are subject to Independent Electricity System Operator (IESO) Market Rules, and (iii) meter data systems which transfer electrical usage data from meters to Alectra Utilities' customer information system.
Investment Drivers and Need	Primary Driver: Mandated Service Obligations Secondary Drivers: Customer Service Requests, Failure Risk
Investment Description	Install and maintain metering installations for a projected 15,000 new services each year over the 2020-2024 planning period; install approximately 250 Metering Inside the Settlement Timeframe (MIST) meters annually on services with monthly demand that exceeds 50kW; annually replace approximately 5,000 meters and other metering equipment that fail or are at end of life; and enhance and maintain meter data communication and processing systems to support accurate and timely customer billing.
Outcomes and Benefits	Service Obligations, Customer Value, Reliability, Safety, Efficiency, Cyber-security and privacy, co-ordination/interoperability, environment, compliance with mandated requirements

Investment Timing and Pacing	Implementation of new metering assets is driven by customer connection requests. Wholesale metering investments are driven by Measurement Canada and IESO Market Rules. Metering replacement timing and pacing is driven by Measurement Canada metering seal dates and technical obsolescence. Please refer to Appendix A01 for more information.
Options Analysis	Metering investments are non-discretionary projects and are required pursuant to Alectra Utilities' distribution licence and associated statutory requirements.

1 ### G.1.2 Customer Connections

Overview	Customer Connections investments involve modifications to Alectra Utilities' distribution system in response to customer requests for connection. Investments include layouts, new services, new subdivisions, renewable generation, as well as customer initiated distribution system projects (such expansion or enhancements to the system when a connection cannot be made with existing infrastructure).
Investment Drivers	Primary Driver: Customer Service Requests Secondary Driver: Mandated Service Requirements
Investment Description	Connections, modifications or realignments to the distribution system that provide Alectra Utilities' customer with access to electricity service. All of the work is mandatory, as it is required to satisfy the conditions of Alectra Utilities' license and DSC.
Outcomes and Benefits	Customer Value, Reliability, Safety, Coordination and Interoperability, Environment, Efficiency
Investment Timing and Pacing	Scheduling of projects is dependent upon timing of customer requests and customers meeting all service conditions. Please refer to Appendix A02 for more information.
Options Analysis	These are mandatory investments pursuant to Alectra Utilities' distribution licence and section 6 of the Distribution System Code (DSC), in which subsection 6.1.1 states *"A distributor shall make every reasonable effort to respond promptly to a customer's request for connection".*

2

G.1.3 Road Authority and Transit Projects

Overview	Road Authority investments are for the relocation or reconstruction of Alectra Utilities' distribution system along public rights-of-way as required per the *Public Service Works on Highways Act*. Transit Project investments include relocation of distribution assets to accommodate Provincial transit agency Metrolinx's implementation of the Hamilton Light Rail Transit ("HaLRT"), Hurontario Light Rail Transit ("HuLRT") and Regional Express Rail ("RER") projects.
Investment Drivers and Need	Primary Driver: Mandated Service Obligations
Investment Description	To accommodate requests from road authorities (as defined in the PSWHA), Alectra Utilities has included plans to relocate and reconstruct assets installed along road allowances that are in conflict with proposed road works. In support of transit projects initiated by the Provincial transit agency Metrolinx, Alectra Utilities has included plans to relocate assets in a timely manner to accommodate the construction and operation of three major transit infrastructure projects. The HaLRT project scope includes the relocation of Alectra Utilities' assets along the 14 km LRT route in Hamilton. The HuLRT project scope includes the relocation of Alectra Utilities' assets along the 20.9 km LRT route in Mississauga and Brampton. The RER project scope includes the relocation of 89 overhead conflicts along the Barrie, Stouffville, Kitchener and Lakeshore West GO Rail Corridors.
Outcomes and Benefits	Customer Value, Reliability, Safety, Efficiency, Coordination and Interoperability, Public Policy

Investment Timing and Pacing	All of the Road Authority and Transit Project investments are mandatory and required to be initiated and completed as per the direction from Road Authorities and Provincial Transit Agencies. Please refer to Appendix A03 for more information.
Options Analysis	These investments are non-discretionary and are required pursuant to the PSWHA.

1 ### G.1.4 Transmitter Related Upgrades

Overview	Consistent with the outcomes of Regional Planning initiatives overseen by the IESO and HONI, Alectra Utilities is required to modify its distribution system to accommodate transmission related renewals and upgrades over the 2020-2024 period.
Investment Drivers and Need	Primary Driver: Mandated Service Obligations Secondary Drivers: Customer Service Requests
Investment Description	Regional Planning identified two HONI transmission assets that are at the end of life and require renewal. HONI has plans to renew transmission assets at Barrie TS and Kenilworth TS. To accommodate HONI's transmission renewal work, Alectra Utilities is required to modify its distribution system and wholesale metering to enable the TS rebuild at these two locations.
Outcomes and Benefits	Reliability, Safety, Environment, Coordination and Interoperability, Efficiency
Investment Timing and Pacing	Transmitter Related Upgrade investments are mandatory projects and are required to be initiated and completed in tandem with Hydro One's transmission asset renewal schedule to replace end-of-life transmission assets identified from Regional Planning initiatives. Please refer to Appendix A04 for more information.
Options Analysis	Investments to modify distribution assets in order to accommodate transmission related upgrades, identified through regional planning, are mandatory in order for Alectra Utilities to be compliant with Section 8 of the DSC.

2

G.2 System Renewal

As described in detail in section 5.2.3, over the past five years Alectra Utilities' customers have experienced an increase in the duration and frequency of outages. Excluding MED outages over the 2014 to 2018 period, Alectra Utilities' customers experienced an 8% annual average increase in outage duration and a 6% annual average increase in outage frequency. Examination of outage causes over the five years indicates that defective equipment is the leading cause of both the duration and frequency of outages. To address this trend, which is unacceptable to both Alectra Utilities and its customers**,** the company has identified and established plans to implement appropriate and prudent solutions to renew deteriorated and unreliable assets over the five year planning period of this DSP. System Renewal investments consist of projects that involve replacing or refurbishing system assets which extend the service life of the assets. For underground cables, which are the leading cause of defective equipment outages, Alectra Utilities plans either to replace or, where feasible, to rehabilitate using silicone injection to extend the life of the cable. The planned System Renewal investments for the 2020-2024 period are set out in Table 5.4.3 - 5 below.

Table 5.4.3 - 5: System Renewal Investments (2020-2024)

	Planned Expenditures ($MM)				
System Renewal	**2020**	**2021**	**2022**	**2023**	**2024**
Overhead Asset Renewal	$34.3	$34.7	$39.4	$30.9	$37.6
Reactive Capital	$18.8	$19.2	$19.6	$20.0	$20.4
Rear Lot Conversion	$4.8	$1.2	$1.2	$4.2	$8.5
Substation Renewal	$12.8	$4.4	$2.8	$3.2	$5.5
Transformer Renewal	$5.5	$6.3	$7.0	$7.4	$7.8
Underground Asset Renewal	$61.1	$74.5	$82.2	$88.5	$95.5
Other System Renewal	$1.7	$1.7	$1.8	$1.9	$1.9
Total	**$139.0**	**$142.0**	**$154.0**	**$156.1**	**$177.2**

System Renewal projects, described below, are identified and planned in a manner consistent with Alectra Utilities' investment principles. In particular, they represent investments in reactive repairs and replacements to the distribution system as required in response to failures or other damage, as well as investments in distribution system renewal in targeted asset categories to mitigate declining reliability due to asset failures and outages. As previously noted, approximately half of the capital to be invested in System Renewal projects is focused on Underground Asset Renewal, which is the primary contributor to declining reliability performance on the system.

1 G.2.1 Overhead Asset Renewal

Overview	Investments in overhead asset replacements are required to replace deteriorated assets, assets prone to catastrophic failure in adverse weather conditions, and deteriorated lower-voltage distribution assets.
Investment Drivers and Need	Primary Driver: Failure Risk Secondary Driver: Reliability, Functional Obsolescence, Resilience to Adverse Weather, Safety
Investment Description	Overhead Asset Renewal investments replace deteriorated assets that are in Poor or Very Poor condition. Investments include renewal of wood and concrete poles, overhead conductors and overhead switches, legacy infrastructure porcelain insulators, first-generation polymeric insulators, legacy wood poles supporting four circuits.
Outcomes and Benefits	Reliability, Safety, Customer Value, Reliability, Efficiency
Investment Timing and Pacing	Investments are paced based on an appropriate balance of mitigating public safety risks, resource constraints and annual cost. Alectra Utilities has incorporated customer preferences to pace the overhead system renewal investment at a moderate pace. Please refer to Appendix A05 for more information.
Options Analysis	Alectra Utilities has considered and evaluated the pacing of overhead system renewals based on replacement of deteriorated assets in Poor or Very Poor condition based on 5, 7.5 and 10 year replacement paces. For storm hardening investments, Alectra Utilities considered installing periodic guying, splitting circuits, and replacing obsolete wood poles with present day standard poles.

	For voltage conversion investments, Alectra Utilities considered a run-to-failure approach; like-for-like replacement of older, lower-voltage equipment; and a full conversion to modern, higher-voltage equipment.

G.2.2 Reactive Capital

Overview	Investments in reactive capital involve the replacement of distribution equipment that has failed during operation and requires immediate attention to restore power. Reactive capital investments also include replacement of assets identified through maintenance and inspections as being of imminent risk of failure or hazard that requires immediate attention to avoid catastrophic failure and safety issues.
Investment Drivers and Need	Primary Driver: Failure Secondary Driver: Reliability, Safety
Investment Description	Reactive capital investment includes, but are not limited to, the replacement of equipment due to storm damage, failure during operations, vehicle accidents or inspection results that require immediate action.
Outcomes and Benefits	Customer Value, Reliability, Safety

1 **G.2.3 Rear-lot Conversion**

Overview	The Rear-lot Conversion initiative is designed to renew rear-lot overhead infrastructure that is deteriorated and functionally obsolete. These assets pose safety risks for the public and for Alectra Utilities' crews, are more prone to failure than other overhead distribution assets, and otherwise do not align with current standards, policies and practices. Due to their location, rear-lot overhead assets are situated near adjacent properties and vegetation. For these reasons, rear-lot infrastructure generally poses a higher risk of failure and elevated safety risks to the general public should the assets fail.
Investment Drivers and Need	Primary Driver: Functional Obsolescence Secondary Drivers: Reliability, Safety
Investment Description	This investment involves the conversion of legacy rear-lot overhead systems to current-standard front-lot underground infrastructure, including the installation of padmounted transformers, tree-retardant cross-linked polyethylene ("TRXLPE") underground cables in conduit and solid dielectric padmounted underground switches. All primary voltage assets will be converted to underground infrastructure. Similarly, all secondary voltage assets will be converted such that customer meter bases will be supplied via underground connections.
Outcomes and Benefits	**Outcomes:** Customer Value, Reliability, Safety, Environment, Efficiency
Options Analysis	Alectra Utilities has considered the following possible options in order to proactively manage existing rear-lot infrastructure:

	• Status Quo / "Do Nothing" • Replace existing Rear-lot Infrastructure with New Rear-lot Overhead Infrastructure • Replace existing Rear-lot Infrastructure with Partial Underground Infrastructure. • Replace existing Rear-lot Infrastructure with Full Underground Infrastructure.

1

1 **G.2.4 Underground Asset Renewal**

Overview	Investments in planned Underground Asset Renewal consist of multi-year and single-year projects to replace or rehabilitate underground assets that are leading to increasingly poor reliability. The underground asset replacement and rehabilitation projects target underground cables and cable accessories, switchgear and civil structures.
Investment Drivers and Need	Primary Driver: Failure Risk Secondary Drivers: Reliability, Functional Obsolescence, and Safety
Investment Description	Through these investments, Alectra Utilities expects to mitigate the increasing risk that customers will experience prolonged and persistent outages due to deteriorating infrastructure. The scope of the renewal projects in this group includes replacing cable and cable accessories that are in Very Poor condition, rehabilitating eligible cable through silicone injection to extend the useful life, replacing switchgear units that are at their end-of-life or in Poor or Very Poor condition, as well as renewing deteriorated civil structures that pose both a public and a worker safety risk.
Outcomes and Benefits	Improved reliability, Fault Finding and Restoration and Improved Safety
Investment Timing and Pacing	Investments are paced based on an appropriate balance of mitigating failure risks, resource constraints and annual cost. Alectra Utilities has incorporated considered customer preferences and will pace the underground system renewal investment at an accelerated pace which improves

	reliability over the DSP planning period. Please refer to Appendix A10 for more information.
Options Analysis	Alectra Utilities has considered alternative pacing of underground asset renewal based on scenarios forecast to improve reliability by 8%, maintain reliability at current levels, and reduce reliability by 10%.

G.2.5 Substation Renewal

Overview	Substation Renewal investments will replace deteriorated and legacy substation infrastructure with new standardized equipment that will align with Alectra Utilities' current practices and processes. These investments will mitigate the risk of station asset failures, which can lead to service disruptions of up to several thousand customers for several hours.
Investment Drivers and Need	Primary Driver: Failure Risk Secondary Drivers: Functional Obsolescence, Safety, Environmental Risk
Investment Description	These investments will renew equipment at eleven stations including station switchgear replacement as MS10, MS59, MS54, MS43, MS47, MS38, MS61 and MS304. In addition, the investments will renew end-of-life transformers and switchgear at MS35 and MS36, and replace circuit breakers at Markham TS#3.
Outcomes and Benefits	Safety, Reliability, Efficiency, Customer Value, Environment
Investment Timing and Pacing	Alectra Utilities has deferred some Substation Renewal projects that would otherwise have been needed during the DSP period. Deferrals were made possible by the implementation of asset monitoring technologies, application of reliability centered maintenance practices and leveraging consolidated inventory of station spares. Please refer to Appendix A08 for more information.
Options Analysis	Alectra Utilities considered alternative scenarios including do nothing, run the relevant assets to failure, or replace those assets that are in Poor or Very Poor condition.

1 **G.2.6 Transformer Renewal**

Overview	Transformer Renewal investments are designed to replace end-of-life and deteriorated overhead and underground distribution transformers across Alectra Utilities' system.
Investment Drivers and Need	Primary Driver: Failure Risk Secondary Driver: Reliability, Functional Obsolescence
Investment Description	Alectra Utilities operates transformers on a run-to-failure basis. However, Alectra Utilities will replace transformers proactively when they are found to be in a condition that introduces an unacceptable safety risk to the public, or to the environmental, (e.g., corroded or damaged enclosure that may expose the public to energized components), or risk of environmental contamination, (e.g., leaking oil), are of obsolete vintage construction, are consistently overloaded, or are configured in a way that increases the likelihood of a lengthy outage due to difficult replacement.
Outcomes and Benefits	Customer Value, Reliability, Safety, Environment
Investment Timing and Pacing	Through its Asset Condition Assessment process, Alectra Utilities has identified 2,998 transformers that are currently in Poor or Very Poor condition. Alectra Utilities plans to replace 1,148 of these transformers through other projects in the DSP, leaving 1,850 transformers that must be replaced through the Transformer Renewal investment. In addition to the Poor and Very Poor condition transformers, Alectra Utilities has identified 900 transformers that must be replaced due to unsafe legacy configuration or which are consistently overloaded. Moreover, during the next five years, Alectra Utilities projects that another 2,000 transformers will deteriorate and will require replacement as well. Alectra Utilities has incorporated customer

	preferences to pace the transformer renewal investment at a moderate pace which addressed 2,750 transformers. Please refer to Appendix A09 for more information.
Options Analysis	Alectra has considered three different investment pacing options, having regard for safety and environmental risks as well as impacts to rates, to manage the deteriorating transformers within its service area.

G.3 System Service

System Service investments are comprised of modifications to Alectra Utilities' distribution system to ensure that operational objectives are met and future customer requirements can be addressed. System Service investments, by sub-category, are shown in Table 5.4.3 - 6. Alectra Utilities' planned System Service investments address a select number of system expansion needs that are necessary to support the utility's Asset Management Objectives for the period and deliver value for customers.

Table 5.4.3 - 6: System Service Investments (2020-2024)

	Planned Expenditures ($MM)				
System Service	**2020**	**2021**	**2022**	**2023**	**2024**
SCADA and Automation	$3.4	$3.6	$3.7	$3.8	$4.7
Capacity (Lines)	$21.1	$24.0	$23.9	$26.4	$14.8
Capacity (Stations)	$0.8	$0.8	$0.8	$5.2	$12.0
System Control, Communications and Performance	$6.6	$5.8	$4.7	$4.1	$2.8
Safety and Security	$5.4	$2.0	$2.0	$2.0	$2.0
DER Integration	$0.7	$0.7	$0.9	$0.9	$0.9
Total	**$38.0**	**$36.9**	**$36.0**	**$42.4**	**$37.2**

1 **G.3.1 SCADA and Automation**

Overview	Investments in SCADA and Automation will continue the expansion of the Supervisory Control and Data Acquisition (SCADA) and Distribution Automation (DA) schemes across the distribution system. These systems are a cost-effective method of improving the reliability, safety, and efficiency of the distribution system, and will allow Alectra Utilities to defer capital investments that would otherwise be needed in the near-term.
Investment Drivers and Need	Primary Driver: Reliability
Investment Description	Through these investments, Alectra Utilities plans to replace obsolete, manually-operated switches with new SCADA-enabled switches and to install new fault detection and isolation equipment. These remote-controlled switches are a central component of Alectra Utilities' DA system, which relies on the ability to quickly and remotely operate switches to isolate faults and restore power more quickly to customers, and to optimize loading of the distribution system.
Outcomes and Benefits	Reliability, Safety, Customer Value, Efficiency
Investment Timing and Pacing	The planned expenditures on these assets over the DSP period are lower than average annual expenditures in the historical period. In planning these expenditures, Alectra Utilities considered customer feedback that these types of investments should be linked to renewal and not done in advance. In order to determine potential candidates for installation of new SCADA-enabled switches, Alectra Utilities prioritizes the worst performing feeders based upon

	reliability, using FAIDI, FAIFI and SAIFI[1] contributions to the system. Alectra Utilities reviews the outage cause codes, feeder load balancing plans and locations of existing automatic switches to identify and determine the locations for additional switches and reclosers where it would be most beneficial in terms of reducing customer minutes interrupted and operational needs. Finally, Alectra Utilities determines the optimal locations for automatic switches by comparing potential switch locations to best address customer service reliability needs, feeder loading emergency back-up and load transfer needs, and control room operations needs for outage sectionalisation and restoration. Please refer to Appendix A11 for more information.
Options Analysis	Options considered were status quo / run to failure, or to proceed with the investments identified.

[1] Feeder Average Interruption Duration Index, Feeder Average Interruption Frequency Index, and System Average Interruption Frequency Index, respectively.

G.3.2 Capacity (Lines)

Overview	The planned Lines Capacity investments are required to ensure that Alectra Utilities' distribution system has sufficient capacity to connect new customers to the distribution system, and to alleviate capacity constraints. The Lines Capacity investments are driven primarily by three factors: (i) the rapid expansion of urban development into historically rural greenfield regions, (ii) the intensification and redevelopment of multiple downtown areas where existing supply is insufficient to meet increased demand, and (iii) the need to address specific locations where customers currently have inadequate backup capacity due to the configuration of existing supply lines.
Investment Drivers and Need	Primary Driver: Capacity Constraints Secondary Driver: Reliability
Investment Description	These investments involve adding new capacity into Alectra Utilities' distribution system to accommodate growth at a system level, enhance the security of supply to customers, and to mitigate loading constraints and the risk of overloading at a localized level. To accomplish these objectives, Alectra Utilities plans to execute the following key actions: • Construct new feeders as well as upgrade existing feeders connecting areas of increasing load growth to the supplying substations; and • Integrate renewable energy technologies, including solar/photovoltaic (PV) and battery storage technologies within specific portions of the distribution system that are experiencing high

	growth, have low reliability or are capacity constrained.
Outcomes and Benefits	Reliability, Customer Value, Efficiency
Investment Timing and Pacing	To minimize the impact on rates, Alectra Utilities has planned feeder expansions and upgrades using a phased approach based on feeder loading requirements paced with the progress of developments and system utilization. This approach ensures that the necessary infrastructure will be in service when required by customers, but minimizes the risk that Alectra Utilities' investments will outpace the growing system needs that drive these expenditures. Please refer to Appendix A12 for more information.
Options Analysis	The following options were considered when evaluating the Lines Capacity projects: • Status Quo: Take no action • Non-wires Alternatives • Construct new feeders to meet system capacity requirements in pace with development, first considering conservation and demand management.

1

1 **G.3.3 Capacity (Stations)**

Overview	Alectra Utilities' Stations Capacity investments consist of construction of new or capacity upgrades at existing substations within Alectra Utilities' service territory over the 2020–2024 period. These investments are necessary to ensure that Alectra Utilities has sufficient capacity for existing and new customers while maintaining system reliability. It also includes forward-looking development work to better utilize Non-Wires Alternatives (NWA) for future distribution system capacity needs.
Investment Drivers and Need	Primary Driver: Capacity Constraints Secondary Driver: Reliability
Investment Description	Alectra Utilities' planned Stations Capacity investments consist of multiple projects for the construction of new, or the expansion of existing TS and MS over the 2020 to 2024 period. These projects will help ensure Alectra Utilities' stations can accommodate peak loading levels and that sufficient spare capacity exists such that if one station is lost in a contingency, the neighbouring stations can accommodate the lost capacity. These investments will also ensure that there is sufficient capacity to connect new customers in areas where load growth is increasing.
Outcomes and Benefits	Ability to service existing and new customers, Reliability, Efficiency, Coordination, Environmental, Grid Modernization
Investment Timing and Pacing	The planned investments in Stations Capacity are needed during the DSP period to ensure Alectra Utilities will be able to meet projected load growth as it materializes. The forecast expenditures are based on the utility's planning methodology, which requires that all station loads can be

	backed up by another station in the planning zone. Alectra Utilities' annual load forecast reflects historical load patterns and expected service growth based on regional, municipal and customer long-term plans. It also accounts for other influences such as CDM and distributed generation programs and rate pricing structures, weather correction or large anticipated loads that are known to Alectra Utilities. Please refer to Appendix A13 for more information.
Options Analysis	In determining feasible alternatives for station capacity investments, Alectra Utilities considered the status quo or do-nothing option, utilization of non-wires alternatives and other wires solutions.

1 **G.3.4 System Control, Communications and Performance**

Overview	During the 2020 to 2024 DSP period, Alectra Utilities plans to renew several categories of equipment that control, monitor, and protect the core distribution system assets across the grid. Several of these critical systems are deteriorated and functionally obsolete, which negatively affects the reliability of service to customers. In the case of monitoring equipment, Alectra Utilities expects to realize significant capital savings during the DSP term by the expanded use of equipment monitoring systems.
Investment Drivers and Need	Primary Driver: Functional Obsolescence Secondary Drivers: Reliability, Power Quality, Safety
Investment Description	During the DSP period, Alectra Utilities plans to invest in the following control and communication systems assets: • Monitoring Equipment: By expanding the use of equipment monitoring systems in its substations, Alectra Utilities expects that it will be able to defer significant capital substation renewal investments. • Fault Indicator Equipment: Alectra Utilities uses fault indicator assets to identify and respond to outages. Fault indicators allow operators to assess where the grid has failed and to quickly restore power to most affected customers. During the 2020-2024 DSP period, Alectra Utilities plans to install or replace fault indicators across the system, with a focus on areas that will result in the greatest benefit to the system and customers. • Protection and Control Equipment: Distribution substations rely on electrically-operated switches (i.e., relays) to operate high voltage circuit breakers, to protect the station bus and other assets from faults and

	over-loading. Many of Alectra Utilities' current relays are deteriorated and functionally obsolete. Over 40% of Alectra Utilities' relays are in Poor condition and need to be replaced. By upgrading to modern, intelligent relays Alectra Utilities will improve reliability and derive other benefits for the distribution system and its customers. • Communication Equipment**:** Alectra Utilities controls and monitors the distribution system and substation operations through a communication network that includes a range of hard-wired (e.g., fibre optic) and wireless equipment. Some elements of that communication system are approaching or at end-of-life, or otherwise unable to process the level of information generated by the increasingly automated and inter-connected grid. During the 2020-2024 DSP period, Alectra Utilities plans to replace and upgrade the wireless communications equipment in several regions and substations. These investments are discussed in Section 2.1.4.
Outcomes and Benefits	Customer Value, Reliability, Safety, Cyber Security and Privacy, Efficiency
Investment Timing and Pacing	Alectra Utilities has increased the pace of investment in System Control, Communications and Performance investments to facilitate deferral of system renewal investments by utilizing reliability centered maintenance practices enabled by improved asset monitoring capabilities. Please refer to Appendix A14 for more information.

Options Analysis	Alectra Utilities has considered several alternative solutions including maintaining status quo (i.e., do nothing), implementing system control and communications infrastructure, leveraging a third-party network, and replacement of legacy system control and communications infrastructure with Alectra-owned and operated infrastructure on a closed network, as well as installation of capacitors in order to manage power quality concerns.

1 **G.3.5 Safety and Security**

Overview	Investments in Safety and Security mitigate safety and security risks across Alectra Utilities' distribution system that are currently exposed to considerable safety and security vulnerabilities. Implementing required reinforcements and upgrades to address these vulnerabilities and prevent potentially serious consequences from materializing will be implemented in an efficient and timely manner. These mitigation efforts are not addressed through other capital portfolios.
Investment Drivers and Need	Primary Driver: Safety Secondary Driver: Reliability
Investment Description	During the DSP period, Alectra Utilities plans to address three specific risks through these investments as noted below: 1.Public safety risks associated with undersized overhead conductors 2.Stations security system risks 3.Environmental contamination risks at Municipal Stations (MS) and Transformer Stations (TS) Investments include safety reinforcement systems along with the removal of certain legacy copper overhead conductors which are undersized relative to load growths and have a high probability of falling to the ground, posing significant safety risks to the public. Investments also include the installation of substation security systems, including upgraded locks, video surveillance, and oil containment systems at Alectra Utilities' MS and TS.
Outcomes and Benefits	Reliability, Safety, Environment, Efficiency

Investment Timing and Pacing	The planned Safety and Security investments are needed during the DSP period. All of the #6 conductors in Alectra Utilities' service area have been identified through asset condition assessment as being in Very Poor condition. The areas selected for replacement under this initiative are the locations where there were no other renewal or expansion projects identified in this DSP. Specifically, five priority areas were identified during the DSP period out of the 25 areas where #6 conductors are currently utilized. Alectra Utilities has substations without oil containment systems. Two of Alectra Utilities' predecessor utilities had not initiated work to install oil containment systems, which is work that has been extended to all operational areas under this initiative. Stations with the highest risk and potential impact of environmental contamination are prioritized. Proximity to water, schools, residential dwellings, community spaces are factors considered determining pacing and prioritization, as well as the condition of the transformers (i.e., to assess the risk of oil leaks). Please refer to Appendix A15 for more information.
Options Analysis	Alectra Utilities considered several feasible options including status quo (i.e., do nothing), investing in projects of only high priorities or investing in all required areas. Alectra Utilities has taken a risk based approach to select preferred options for this portfolio, considering both public safety risk and risk of environmental contamination.

G.3.6 DER Integration

Overview	The Distributed Energy Resource ("DER") Integration investments will build Alectra Utilities' capability to monitor; control; and optimize the integration of DERs (e.g., solar generation, battery storage, smart thermostats, electric vehicles ("EVs")) into the distribution system, and to provide real-time transparent, tracking and management of DER participation in energy services. The investments that are planned for the 2020-2024 period will enable Alectra Utilities to effectively serve the increasing amount of customers that already are and will continue to adopt DERs in its service area. Ontario already has at least 4,100 MW of DERs that have been contracted or installed in the last 10 years[1]. This DER capacity growth closely rivals the 5,600 MW net growth in transmission-connected generation added during that same time period.
Investment Drivers and Need	Primary Driver: Capacity Constraints Secondary Drivers: Customer Access and Choice
Investment Description	The DER Integration investment is required to implement two related projects to develop Alectra Utilities' capability to monitor, control and optimize the integration of DERs onto the distribution system. The DER Integration investments consist of two projects: (1) DER Control Platform: This project will integrate DERs with Alectra Utilities' traditional distribution

[1] IESO. (2018). 2018 Electricity Data. Retrieved from http://www.ieso.ca/en/Corporate-IESO/Media/Year-End-Data.

	operation systems and enable the utility to optimize the operation of DERs. (2) Smart DER Platform: This project will involve the development of a platform that utilizes blockchain technology to enable real-time processes for procurement, smart contracting, automated verification and settlement for customers participating in grid services with their DERs.
Outcomes and Benefits	Customer Access and Choice, Infrastructure Expansion Deferral
Investment Timing and Pacing	These pilot projects must be implemented now to enable Alectra Utilities to prepare its distribution system to safely and reliably respond to the expected uptake of DERs with a coordinated architecture that balances the benefits of DERs to their owners, with the costs they potentially pose on all of Alectra Utilities' customer-base and maximize the benefit of DERs for all customers connected to the distribution system. Please refer to Appendix A16 for more information.
Options Analysis	Alectra Utilities considered several options including status quo (i.e. do nothing), reactively responding to DER uptake or evaluating DER integration.

G.4 General Plant

General Plant investments are comprised of modifications, replacements or additions to Alectra Utilities' assets where these assets are not part of the electrical distribution system (e.g., land, trucks, computers etc.). General Plant investments are shown in Table 5.4.3 - 7.

Table 5.4.3 - 7: General Plant Investments (2020-2024)

	Planned Expenditures ($MM)				
General Plant	**2020**	**2021**	**2022**	**2023**	**2024**
Facilities Management	$4.2	$2.6	$2.9	$4.6	$3.5
Information Technology	$15.1	$18.2	$19.8	$12.3	$8.4
Tools, Shop and Garage Equipment	$1.3	$1.3	$1.3	$1.3	$1.3
Fleet Renewal	$8.9	$9.5	$9.9	$10.3	$10.2
Connection and Cost Recovery Agreements	$8.7	$1.6	$0.0	$0.5	$0.0
Other General Plant	$1.2	$1.2	$1.2	$1.2	$1.3
Total	**$39.4**	**$34.4**	**$35.1**	**$30.2**	**$24.7**

1 **G.4.1 Facilities Management**

Overview	Facilities Management investments are for improvements that are integral to the proper functioning of assets and ongoing business operations. During the DSP period, Alectra Utilities' focus is to: (i) to renew security cameras and access control equipment that have reached end-of-life and are technically obsolete; (ii) to renew these elevator and generator systems; (iii) renewal HVAC systems for specific buildings;(iv) address issues affecting the building envelope; (vi) address issues affecting outdoor walkways and driveways; and (vii) optimize work spaces and install new or refurbished workstations to Alectra Utilities' standards and accessibility requirements.
Investment Drivers and Need	Primary Driver: System Maintenance and Capital Investment Support Secondary Drivers: Reliability, Safety, Failure Risk
Investment Description	During the DSP period, Alectra Utilities plans to invest primarily in the following facilities categories: 1. Security/Life Safety 2. Elevators and Generators 3. Building HVAC 4. Building Envelope 5. Building Outdoor Walkways/Driveways 6. Building Renewal These investments ensure that Alectra Utilities' operating and administrative infrastructure (e.g., IT systems, control rooms, operations centers and work offices) serve Alectra Utilities customers and respond to operational demands, especially in response to emergencies. These investments

	will also ensure that all Alectra Utilities' facilities comply with applicable regulatory standards, including safety requirements that protect employees and the general public.
Outcomes and Benefits	Reliability, Safety, Efficiency, Customer Value, Reliability, Environment
Investment Timing and Pacing	Increase over historical investment levels. Please refer to Appendix A17 for more information.
Options Analysis	Options included "Status Quo" / "Do Nothing" or the prioritized risk based approach.

1 **G.4.2 Information Technology Systems**

Overview	Investments in Information Technology are for maintaining and renewing hardware and for updating software and communications technology and maintaining cyber security systems.
Investment Drivers and Need	Primary Driver: System Capital and Maintenance Investment Support Secondary Driver: Functional Obsolescence
Investment Description	Software: Updates to several key software tools, including: (i) the Meter-to-Cash Framework that Alectra Utilities relies on to bill customers accurately and on-time; (ii) the systems that it uses to respond to outages and to plan and execute capital investments; and (iii) the Enterprise Resource Planning system that it uses to run many core elements of the company. Hardware: Updates to several key hardware components that Alectra Utilities uses to operate the utility. The investments in this category are to maintain and renew end-of-life assets in the utility's control room, corporate network, and business offices. IT Security: Maintain cyber-security systems that are sufficient to meet evolving cyber-security risks. Business Optimization investments will allow Alectra Utilities to work more effectively and deliver higher quality of service to its customers through the utility's website.
Outcomes and Benefits	Efficiency, Customer Value, Reliability, Safety, Cyber Security and Privacy, Coordination and Interoperability, Environment

Investment Timing and Pacing	Pacing and prioritization varies across the IT upgrades and enhancement program depending on the form of investment. Please refer to Appendix A18 for more information.
Options Analysis	Options included “Status Quo” / “Do Nothing” or the investments specified.

1 **G.4.3 Fleet Renewal**

Overview	The planned Fleet Renewal investments are necessary to manage the approximately 560 vehicles, 156 trailers, and other miscellaneous equipment used to perform the utility's daily activities and projects. During the DSP period, Alectra Utilities' planned fleet investments are focused on renewing vehicles that are either in Poor condition, have high mileage/engine usage or have surpassed their end of life. Alectra Utilities does not propose to increase the size of the utility's fleet in this period.
Investment Drivers and Need	Primary Drivers: System Capital and Maintenance Work Support Secondary Driver: Business Operations Efficiency
Investment Description	A significant number of vehicles in Alectra Utilities' fleet have deteriorated to unacceptable levels. These vehicles pose safety risks for employees and the general public and must be replaced. To the extent that they are unable to fulfil their operational functions, either partially or entirely, these deteriorated vehicles negatively impact Alectra Utilities' ability to serve its customers. Replacing these vehicles is the focus of Alectra Utilities' fleet investments during the DSP period.
Outcomes and Benefits	Customer Value, Safety, Reliability, Environment and Efficiency
Investment Timing and Pacing	The planned investments in Alectra Utilities' fleet are needed during the DSP period to ensure the utility's vehicles are available and in a condition to effectively

	support operations, reduce potential safety risks to employees and public, and to operate efficiently. To execute and sufficiently pace and prioritize the Fleet Renewal investment, Alectra Utilities implemented a first pass screening process which includes an assessment of the vehicle type, usage and age. At this time, the vehicles' mileage, engine hours, utilization, and "power take off" hours are documented. This assessment provides Alectra Utilities a baseline to initiate the capital replacement assessment process. During this time, the vehicle utilization is also examined and internal discussions take place with various business units on the vehicle requirement. Alectra Utilities examines the possibility to re-allocate vehicles to maximize utilization as well as considers replacement options. Please refer to Appendix A19 for more information.
Options Analysis	In addition to the planned investments, Alectra Utilities considered scenarios under which it would (i) run its existing vehicles until they failed, (ii) replace only portions of the utility's heavy-duty vehicles, (iii) purchase demonstration model vehicles rather than new and (iv) replacing fleet vehicles based on Alectra Utilities Renewal Criteria.

G.4.4 Connection and Cost Recovery Agreements (CCRA)

Overview	Investments in CCRAs refers to the contributions required to be made to Hydro One Networks Inc. ("HONI") to meet the revenue shortfall for the expansion of TS facilities that serve Alectra Utilities. Alectra forecasts that the over the 2020-2024 DSP period, approximately \$10.8 MM will be required for four stations where the incremental load forecasted in the CCRA document will be greater than the actual demand thereby creating a revenue shortfall for HONI and triggering a capital contribution. This is included within General Plant as it is considered to be an intangible asset similar to IT related projects and therefore does not fall within the other investment categories.
Investment Drivers and Need	Primary Driver: Mandated Service Obligations Secondary Driver: System Maintenance and Capital Investment Support
Investment Description	As per the Transmission System Code ("TSC"), for any new or expanded transmitter owned connection facilities HONI is required to execute a CCRA with the proponent for the connection and includes customer load guarantees, cost responsibility, scope of work and any initial capital contribution which is the shortfall of revenue not recovered through rates. Over the 2020-2024 period, capital contributions of approximately \$10.9MM will be required for four stations, Nebo, Midhurst, Vansickle, and Goreway, where the incremental load forecasted in the corresponding CCRAs will be greater than the actual demand, thereby giving rise

	to a revenue shortfall for HONI that triggers capital contributions under the CCRAs.
Outcomes and Benefits	Customer Value, Reliability
Investment Timing and Pacing	In accordance with the terms and conditions set out in each specific agreement. Please refer to Appendix A20 for more information.
Options Analysis	Mandatory investment based on terms and conditions set in each specific agreement.

INVESTMENT SUMMARIES

Alectra Utilities has provided comprehensive Investment Summaries for each Investment Group, as provided in Appendix A and shown in Table 5.4.3 - 8 below.

Table 5.4.3 - 8: List of Investment Summaries and Their Corresponding Appendix Location

Investment Category	Investment Group	Investment Summary
System Access	Network Metering	Appendix A01
	Customer Connection	Appendix A02
	Road Authority and Transit Projects	Appendix A03
	Transmitter Related Upgrades	Appendix A04
System Renewal	Overhead Asset Renewal	Appendix A05
	Reactive Capital	Appendix A06
	Rear-lot Conversion	Appendix A07
	Substation Renewal	Appendix A08
	Transformer Renewal	Appendix A09
	Underground Asset Renewal	Appendix A10
System Service	SCADA and Automation	Appendix A11
	Lines Capacity	Appendix A12
	Stations Capacity	Appendix A13
	System Control, Communications and Performance	Appendix A14
	Safety and Security	Appendix A15
	Distributed Energy Resources	Appendix A16
General Plant	Facilities Management	Appendix A17
	Information Technology Systems	Appendix A18
	Transportation Equipment	Appendix A19
	Connection and Cost Recovery Agreements (CCRA)	Appendix A20

5.4.3.2 BUSINESS CASES FOR MATERIAL INVESTMENTS

Alectra Utilities' materiality threshold is $1MM. For each project over that threshold, which include multi-year projects, a business case has been provided as follows. These material investments are provided in Appendix B - Material Investment Business Cases.

Appendix A

Investment Summaries

Alectra Utilities

Distribution System Plan (2020-2024)

Appendix A01 - Network Metering

I Overview

Alectra Utilities manages meters, meter data communication and processing systems, and meter testing facilities and equipment that serve approximately 991,000 customer accounts and 215 wholesale metering points.

The assets in the Network Metering portfolio generally fall into three categories of metering-related assets on Alectra Utilities' distribution system:

- Metering equipment serving distribution customers;
- Metering equipment on wholesale metering points subject to Independent Electricity System Operator ("IESO") Market Rules; and
- Meter data systems which transfer electrical usage data from meters to Alectra Utilities' customer information system.

During the term of the DSP, Alectra Utilities plans to invest in these three categories to satisfy its mandatory service obligations, including distribution licence conditions, Ontario Energy Board ("OEB") requirements as outlined in the Distribution System Code ("DSC"), Measurement Canada requirements as outlined in the *Weights and Measures Act* as well as the *Electricity and Gas Inspection Act*, and IESO Market Rules.

Some of the planned investments are also driven by other factors. Those factors include the need to:

- the company's need to respond to customer service requests;
- replace or refurbished (renew) metering assets that fail,
- replace metering assets that contain higher concentrations of PCBs than permitted by regulations; and
- replace smart meters that lack modern data-encryption capabilities as recommended in a cyber-security audit, and to align with the Ontario Cyber Security Framework.

1.1 Major Investment Categories

The majority of the planned investment in Network Metering over the 2020-2024 period consists of the following work:

- Annually installing metering equipment for an estimated 15,000 new services;
- Annually renewing approximately 5,000 meters and other metering equipment that fail;
- Annually installing approximately 250 Metering Inside the Settlement Timeframe ("MIST") meters and communication equipment on services with monthly demand that exceeds 50kW; and
- Enhancing and renewing meter data communication and processing systems to support accurate and timely customer billing.

1.2 Other Investment Categories

Alectra Utilities also plans to renew certain metering assets to satisfy environmental regulations, cyber-security requirements, and customer requests.

Alectra Utilities plans to renew five Metering Potential Transformers identified as containing a greater concentration of polychlorinated biphenyl ("PCB") than is allowed. These specialized transformers are used in some metering installations to step-down higher-voltage service to more manageable levels for metering. Pursuant to federal PCB Regulations SOR/2008-273, made under the *Canadian Environmental Protection Act, 1999*, Alectra Utilities is required to remove from service all Metering Potential Transformers containing greater than 50 mg of PCB per kilogram by December 31, 2025. Alectra Utilities has identified five such transformers, all of which it plans to renew by the end of the DSP term.

Some investment is needed to address cyber-security risks related to older smart meters. Alectra Utilities has identified a group of first-generation smart meters that do not support modern levels of data encryption. Alectra Utilities must replace these older smart meters as recommended in a cyber-security audit, and to align with the Ontario Cyber Security Framework issued by the OEB.[67]

[67] On March 15, 2018, the Ontario Energy Board amended the Transmission System Code and Distribution System Code requiring licensed electricity transmitters and distributors in Ontario to report on their cybersecurity preparedness relative to the newly-established Ontario Cyber Security Framework. The code amendments define "cyber security" as "a body of technologies, processes, and practices designed to

To protect operational data, Alectra Utilities plans to replace all of these meters during the DSP period.

Alectra Utilities is often required to replace metering equipment due to customer requests. These requests may relate to the location of a meter, the type of meter used, or various other factors. Costs are recovered from the customer for services requests.

1.3 Benefits of Network Metering Investments

In addition to allowing Alectra Utilities to satisfy all applicable metering-related compliance obligations, key benefits of the Network Metering program include:

- Customer online access to recent MIST meter electrical usage data, to facilitate consumption management;
- Improved response to outages by increasing the number of meters that can transmit outage alarms;
- Reduced costs by reducing the number of meters that are read manually every month; and
- Enhanced meter cyber-security and reduced environmental risk.

The benefits of the Network Metering investments are described in section 2.1 below.

1.4 Execution of Network Metering Work

The Network Metering investments will be executed by a combination of internal staff and outside service providers to ensure that sufficient capacity is optimized and available to execute both planned work and unplanned work that may arise. The execution approach is discussed in section 4.5 below.

protect networks, computers, programs, data and personal information from attack, damage or unauthorized access", and reference both electronic and physical security. The framework is published here: https://www.oeb.ca/sites/default/files/Ontario-Cyber-Security-Framework-20171206.pdf.

Table A01 - 1: Investment Subgroup Summary

	Historical Spending				Bridge	Forecast Spending				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$18.1	$9.4	$12.2	$10.8	$14.3	$14.8	$14.3	$10.2	$11.6	$12.2
Primary Driver:	Mandated Service Obligations									
Secondary Drivers:	Customer Service Requests, Failure Risk									
Outcomes:	Customer Value, Reliability, Safety, Cyber Security and Privacy, Coordination and Interoperability, Environment, Compliance with Mandated Requirements									

II Investment Description

The work conducted through the Network Metering portfolio addresses three general categories of metering assets on Alectra Utilities' distribution system:

- Metering equipment for distribution customers,
- Meter data systems that transfer electrical usage data from meters to Alectra Utilities' customer information system ("CIS"), and
- Metering equipment on wholesale metering points subject to IESO Market Rules.

2.1 Distribution Customer Metering

Alectra Utilities installs and maintains electrical metering for new and existing services, as required by the DSC. Equipment required depends on the size and voltage of the service, and the customer category (i.e., residential, general service <50kW demand, general service >50kW demand, and large customers). Metering equipment and installation configurations vary, ranging from a self-contained smart meter, to instrument transformers, test block, communication modem, and meters capable of providing power quality analysis and data output to customer devices. Metering installations (typically located downstream of the customer demarcation point) are chosen according to Alectra Utilities standards. Alectra Utilities tests the accuracy of installations that include instrument transformers to ensure compliance with Measurement Canada requirements.

Alectra Utilities must invest in metering systems to both accommodate customer growth and address failing meters at current customers services. At the end of 2018, Alectra Utilities had 991,000 customer accounts. The utility's projections indicate that approximately 15,000 new services will be added each year which drive the demand for new and upgraded metering services, and the need to maintain an increasing fleet of metering and communication equipment. Costs for metering equipment for new and upgraded services are funded by rates or customer payments calculated through an economic evaluation as per the applicable conditions of service. Based on historical trends, Alectra Utilities projects that approximately 5,000 meters (approximately 0.5% of the network meter population) will fail each year.

The remainder of this section is sub-divided between major categories of work planned for distribution customer metering.

2.1.1 Renewing Meters

The number of meters with expiring seals (which will therefore require refurbishment or replacement) is detailed in Table A01 - 2.

Table A01 - 2: Number of Meters to be Renewed

Year	Meters to be Replaced or Refurbished
2019	238,000
2020	138,000
2021	36,000
2022	30,000
2023	52,000
2024	31,000

The number of expired meters on Alectra Utilities' distribution system has increased from 2016 to 2018, and is expected to peak in 2019. This trend follows the 10-year seal period of meters installed in the residential smart meter implementation program. Commercial and industrial smart- and MIST-meter implementation started 3 to 10 years after residential smart meter implementation, depending on the rate zone. Despite the decrease in expired meters, Alectra Utilities expects the annual number of meters refurbished will not decrease from 2020 to 2024. As homogeneous groups (i.e., meters that can be tested by sampling) decrease in size, the proportion of meters that require comprehensive testing will increase. In addition, more labour is needed to replace and refurbish a Commercial and Industrial meter than a residential meter. Starting in 2019 and carrying on through 2024, the investment to renew expired meters will increase as suite meters reach their first seal expiry. The investment to renew expired meters will also increase in the years 2023 and 2024 due the higher number of Commercial and Industrial meters.

Alectra Utilities' practice is to extend the useful life of meters by executing refurbishments per Measurement Canada standards. However, there are specific circumstances that a utility must satisfy before it is permitted to refurbish (rather than replace) meters. Through its enforcement of the *Weights and Measures Act* and *Electricity and Gas Inspections Act*, Measurement Canada administers the requirements and standards that ensure accurate electrical metering. Alectra

Utilities procures meters and metering instrument transformers approved by Measurement Canada. Metering installations are constructed in compliance with Measurement Canada and Alectra Utilities standards. Meters are certified to Measurement Canada standards for a set period (up to 10 years) which is reflected by the meter certificate and a seal affixed to the meter. The meter can only be used to charge a customer for electrical usage during this seal life, after which it is removed from service.

When a meter reaches the end of its seal life, it may be possible to refurbish the meter rather than scrap it. Meters may only be refurbished at a Measurement Canada certified Meter Testing Facility. Alectra Utilities' meter refurbishment work involves replacing the expired meter with a valid meter, testing the expired meter at Alectra Utilities' Meter Testing Facility, resealing the expired meter to achieve an extended seal date (if applicable test is passed), or scrapping the meter (if failed).

According to Measurement Canada requirements, a utility may either test all meters, or it may test a statistical sample of a homogeneous group as a proxy of the condition of the whole group. If a sample passes, the remainder of the group will remain in the field and the records reflect the new seal date. If the sample fails, the utility remove and scrap the whole group, or it may test each meter individually. Samples receive a decreasing seal extension. The choice to test 100% of a group or a sample is made by Alectra Utilities based on the predicted success of the test, the size of the group, and the number of years of the potential seal extension.

The number of meters tested by Alectra Utilities depends on the size of the homogeneous sample and type of meter. Residential socket meters are typically sampled due to the large group size. All multi-unit metering (suite metering) meters are tested due to the small group size of meter heads. All large customer and IESO Wholesale meters are tested due to their smaller population. If one or more sample groups fail, the number of meters to be refurbished each year can increase anywhere from 3,000 to 25,000 units. Alectra Utilities will consider the feasibility of refurbishing an entire group of meters if data on the groups meter health indicates the sample will fail.

The number of Alectra Utilities' customer accounts by customer category at year-end 2018 is outlined in Table A01 - 3.

Table A01 - 3: Number of Customer Accounts by Category

Customer Account Type	Number of Accounts
Residential Socket Meter	921,000
Residential Multi Unit (Suite) Meter	28,000
General Service with demand =<50KW	84,000
General Service with demand >50kW	14,000
Large User	33
TOTAL	1,047,033

During the DSP period, Alectra Utilities plans to replace one of the Measurement Canada certified test boards to ensure compliance with Measurement Canada and IESO. Alectra Utilities maintains a Measurement Canada-certified test facility to test meter accuracy as part of the meter seal life refurbishment program and resolve customers' concerns about meter accuracy. To maximize use of the meter, a meter is removed from service and tested in the year it expires. If a meter group is sampled, the sample must be tested with enough time remaining in the year to replace the whole group, in case the sample fails. Alectra Utilities requires capacity to test expired meters in a timely fashion. The manufacturer of five of Alectra Utilities' six test boards does not provide parts and service support. Given that these devices are made with custom equipment and software, a single component failure may result in permanent loss of a board. The loss of multiple boards would prevent Alectra Utilities' from completing the meter refurbishment program, as required by Measurement Canada. Timing of failure of one of the five older test boards is not predictable. Delivery of a test board is one year. Timing for investment in additional test boards will be based on actual failures.

Alectra Utilities also plans to renew portable meter testing devices as equipment fails. The testing equipment measures voltage, amperage and carries out phase analysis on metering installations. These tests ensure metering installations are accurate when commissioned, when changes are made, or in response to customer concerns. Accurate metering ensures accurate billing of electrical consumption.

2.1.2 New Connection Meters

Alectra Utilities plans to install 14,500 additional Advanced Metering Infrastructure ("AMI") meters every year and 500 additional MIST meters each year to accommodate new services. In 2020, Alectra Utilities will add an additional 1,000 MIST meters and associated communication equipment.

Alectra Utilities must install MIST meters and associated communication equipment on all new or existing metering installations that have a monthly average peak demand during a calendar year of over 50 kW. These are interval meters from which data is obtained and validated within a designated settlement timeframe (i.e. billing period). Alectra Utilities will be replacing meters that are read manually with those that can be read remotely. These meters will support Hourly Ontario Energy Price ("HOEP") billing. The meter data will be available for review by the customer within days of usage through an online portal. Alectra Utilities plans to complete these installations by August 21, 2020, as required by the DSC. The costs of this work will be recorded in the OEB's established MIST Meters Capital account 1557. Alectra Utilities does not propose to recover costs for MIST meter implementation in base rates. The OEB amended the Distribution System Code ("DSC") on May 21, 2014 to establish a requirement for the installation of Metering Inside the Settlement Timeframe ("MIST") meters. The changes came into force on August 21, 2014. Distributors have until August 21, 2020 to install the required meters. The OEB established a deferral account to allow distributors to capture prudently incurred incremental costs that are material and are associated with the subject amendment. Alectra Utilities will continue to record prudently incurred incremental costs in the OEB-approved deferral account during 2020. Cost will be audited prior to approval for disposition. Approved costs are then collected through a rate rider on customer bills, with term length subject to approval by the OEB.

2.1.3 Metering-Related Customer Service Requests

Alectra Utilities also renews distribution customer metering equipment in response to customer service requests. This can involve changing the location of the installation, changing the type of metering (such as metering the secondary or primary conductors), or installing meters and communication devices that allow controlled customer access to metering data. Costs are recovered from the customer for services requests.

2.1.4 Metering Equipment that pose Cyber-Security or Environmental Risk

Alectra Utilities must invest to replace distribution customer metering equipment that pose a cyber-security risk, or fail to comply with environmental standards. Alectra Utilities has identified two such categories of investment in the 2020-2024 DSP period related to older smart meters and metering equipment that contains higher concentrations of PCBs.

Alectra Utilities' distribution system includes first-generation Sensus iCON F residential smart meters. These meters do not use modern standard of data encryption, and must be replaced as recommended in a cyber-security audit, and for Alectra Utilities to align with the Ontario Cyber Security Framework issued by the OEB. Unlike more recent smart meters, the firmware of the iCON F meters cannot be updated with more effective encryption. The security risk was identified in a cyber-security audit of the legacy PowerStream AMI system in 2011. The meter data integrity is at risk, which places the accuracy of customers' bills at risk. Alectra Utilities started a nine-year project to replace the entire group of 108,000 meters in 2013 with newer, more cyber-secure meters with firmware that can be upgraded. The project is planned to complete meter replacement and associated elimination of the cyber-security risk in 2021. The pace of the project has higher volume of meter replacements at the end of the project to optimize use of the assets before they are scrapped, while meeting the planned date for elimination of this risk.

Alectra Utilities plans to replace a total of 61,000 iCON F meters over the DSP term. The number of iCON F meters to be replaced by year is detailed in Table A01 - 4:

Table A01 - 4: First-Generation Sensus (iCON F) Meters to be Replaced

Year	Meters to be Replaced
2020	26,000
2021	35,000
TOTAL	61,000

Alectra Utilities' predecessor, PowerStream, and a consortium of 32 Ontario LDCs hired Bell Wurldtech in 2010 to carry out a comprehensive audit of the Sensus AMI from meter data capture to Regional Network Interface ("RNI") output file. The audit commenced in February 2011, completed in December 2011, and the review with the consortium took place in February 2012. This was the first comprehensive AMI Threat and Risk Assessment in North America. The audit goal was to determine the ability of the Sensus AMI systems to maintain operational integrity and functional performance under real-world network conditions, as well as abnormal traffic variations and simulated malicious attack scenarios. The PowerStream AMI system and Test Facility were the host for the audit.

The audit objectives were:

- Conduct a technical security evaluation of the Sensus AMI systems in use by Ontario LDC Consortium members;
- Identify vulnerabilities and weaknesses that could allow meter, communications infrastructure or head end compromise through direct access to the meter and/or communications infrastructure including Radio Frequency access, physical access, software access;
- Classify meter, gateway and head end security threats according to complexity, impact and overall severity in order to prioritise mitigation actions; and
- Recommend mitigation actions to address identified weaknesses in the tested systems and future security enhancements for those same systems

Audit Key Findings – Vulnerabilities and Actions:

- Weak credentials and/or access controls – i.e. passwords and authentication
  - Addressed by PowerStream and Sensus
- RNI has unprotected Internet access
  - Addressed by Sensus
- Too many Sensus staff with AMI access
  - Addressed by Sensus
- Encryption not enabled allowing access to meter data transmissions and control actions
  - Encryption of iCon “G” and “A” series meters will address meter data access vulnerability
  - iCon “F” series meters cannot support encryption

Bell Wurldtech summary of the specific risk associated with the iCON F meter was:

- Findings

- Unauthorised Users can attack and change meter configuration or communication parameters
- Encryption is not supported on some models of (Sensus) meters

- Recommendations and Next Steps
  - Enable encryption for meter communications
    - Replace meters which do not support encryption with ones which do
    - iCON F meters do not support encryption and would need to be replaced"
- Implications of Unauthorised Smart Meter Access
  - Attacker can modify transmission frequency, frequency of meter communication and meter consumption data:
    - Enables "denial of service" attacks by flooding the network with signals;
    - Necessitates site visit by a metering technician to investigate and repair/replace the communications model or meter;
    - Impairs billing accuracy and revenue integrity; and
    - Interferes with critical operational data transmission e.g. outage reporting.
  - Fails consumer privacy protection standards and requirements of the Ontario Privacy Commissioner.
  - Encourages further attacks once the vulnerability becomes known to the "Hacker Community" and would ultimately impair Consumer confidence in data security and billing accuracy and integrity.

The iCON F meters also do not have "last gasp" or "hot socket alarm" capabilities. They do not provide a signal to the AMI head end when they lose power. This "last gasp" signal is passed to the Outage Management System. As well as identifying individual customers, the Outage Management System uses signals from multiple meters to determine when power is interrupted for a transformer, or a feeder. This results in prompt identification of the required action and dispatch of crews to restore power. This is much faster than relying on calls from customers, and it identifies outages even when the customer is not at home. A worn or faulty customer meter socket will not provide a good connection with the electric meter. This can result in heat from electrical resistance at the meter jaws. Heat build up from a "hot socket" can result in damage to customer equipment or their premises. The replacement meters have temperature sensors that detect "hot sockets" and send an alarm to the AMI head end, so Alectra can dispatch staff investigate the issue. Carrying out this work after 2021 will be higher due to an increase in meter costs. The meters have a 15 year depreciation period and were installed from 2007 to 2009. They will be removed from service with 80% of their capital value depreciated. During customer engagement, approximately one half of customers supported the original iCON F project pace and cost. In response to this feedback, Alectra reduced costs of this project by increasing the use outside labour to 100%.

Alectra Utilities also plans to address metering installations with Metering Potential Transformers containing greater permitted concentrations of PCBs. Federal PCB Regulations require equipment containing between 50 mg/kg and 500 mg/kg of PCB to be removed from service by December 31, 2025.[68] Alectra Utilities has identified five Metering Potential Transformers that must be removed pursuant to the regulation.

2.2 Meter Data Systems

Alectra Utilities must renew metering installations and meter data communication systems to provide timely and accurate meter data that in turn supports accurate customer billing. As part of this program, Alectra Utilities plans to renew failed communication equipment. In addition, Alectra Utilities must expand its meter data communication network in the field to accommodate the increasing number of meters and the increasing flow of data over the utility's systems. Equipment installed as part of this investment includes radio towers, pole mounted data collectors, modems, radio repeaters and signal boosters, and antennae.

Alectra Utilities inspects and replaces metering equipment when inaccurate data transmittal is identified. Faulty metering equipment may be identified by alarms from the meter data management system, customer information system, or staff in the field. Alectra Utilities updates meter communication firmware (i.e., the software embedded in the meter itself) when a patch is provided by the vendor to address a known issue affecting the current firmware version. These updates are either conducted remotely via the meter data communication system or through on-site visits.

The meter data communication and management systems need to be renewed and enhanced to ensure reliable and secure customer billing. Smart meter data is used for Time-Of-Use billing for

[68] Federal PCB Regulation SOR/2008-273 made under the *Canadian Environmental Protection Act*.

customers with an average monthly demand up to 50kW, and interval meter data is used for customers with an average monthly demand greater than 50kW. Several systems receive meter data and meter alarms and transmit signals or firmware upgrades to meters. Most meters (residential and commercial/industrial) have integrated AMI radios that transmit data to central towers or a mesh network of data collectors, which in turn convey the data (through TCIP modems) to AMI head ends. Some metering installations have separate modems with TCIP communication to AMI head ends.

Alectra Utilities also plans to enhance the reliability of the meter data systems through periodic audits, software updates, and testing of selected new meters and communication equipment prior to implementation. Alectra Utilities plans to hire an independent expert to conduct periodic data security audits of the utility's AMI systems to identify areas of risk and required remedial actions, and add capacity to the Meter Field Test facility to support increased testing of new meters and meter data communication devices, including concurrent real-world trials of meters and associated communication devices. Rigorous testing (prior to field deployment) will reduce the risk of equipment failure and ensure the proper integration of new equipment into the existing meter data management systems. In addition, the vendors for Alectra Utilities' AMI systems offer periodic software updates to improve performance, increase functionality, and support changes in regulatory requirements. Alectra Utilities will determine the need and timing to implement updates to our systems based the costs, benefits, risks, and regulatory changes.

2.3 Wholesale Metering

During the DSP period, Alectra Utilities must replace metering equipment at IESO monitored wholesale metering points to ensure compliance with current IESO standards. This program includes replacing and testing meters to Measurement Canada regulations, replacing metering equipment that fails, and replacing and enhancing communications equipment to wireless data standards.

Alectra Utilities has 215 IESO wholesale metering installations, with 430 meters.

2.4 Summary of Investment Outcomes and Benefits

Table A01 - 5 summarizes the outcomes and benefits associated with the Network Metering program.

Table A01 - 5: Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Customer Value	Increase customer value by replacing manually-read meters with remotely-read meters, which will: • provide customers with online access to electrical usage data that is less than five days old, • allow customers to manage their electrical load and predict their bill using current data, and • minimize the number of days where Alectra Utilities must estimate the electrical usage on customers' bills due to meter failure (the Meter Data Systems identify potential metering errors within 7 days, instead of the monthly manual meter read cycle). • reduce the length of power outages by increasing number of meters which send a signal to the Outage Management system when they lose power. • reduce the risk of damage to customer equipment by increasing number of meters which detect and send an alarm for a "hot socket (over temperature meter socket which indicates a worn or faulty customer equipment..
Reliability	Improve Alectra Utilities' response to customer outages by: • Replacing failed older SMART meters with new ones that send "lost power" alarms to the Outage Management System, which in turn notifies Control Room staff of the location and scope of outages (sometimes before customers can contact Customer Service or realize there is an outage), resulting in faster restoration of power; and • Enhancing communication during power outages by increasing the number of AMI field communication devices with battery backup.

Outcome	Investment Benefits and Objectives
	• Ensuring sustained capability to continue Alectra Utilities' internal meter refurbishment investment (and thereby avoiding non-compliance with Measurement Canada requirements) by replacing Alectra Utilities' older meter test boards no longer supported by the manufacturer.
Safety	The installation of remotely read meters will reduce the frequency and need of Alectra Utilities staff visits to customer sites, which may otherwise pose several safety hazards for Alectra Utilities personnel (e.g., electrical exposure, arc flash, dangerous dogs, slips/trips, mold, and animal biohazards).
Environment	Reducing vehicle use by switching to meters that are read remotely.
Cyber-security and Privacy	Increase the security of Alectra Utilities' metering data by replacing first generation Sensus iCON F residential meters as recommended in a cyber-security audit.
Co-ordination / interoperability	Enhancing the capability of Alectra Utilities' Meter Test Facility to test meters and AMI systems in real-world conditions, thus reducing the risk that new meters and related equipment will not function reliably.
Compliance with Mandated Requirements	Ensuring Alectra Utilities' compliance with DSC metering requirements by: • Installing and maintaining a meter installation for settlement and billing purposes for each customer connected to the distribution system; • Installing and maintaining a MIST meter, by August 21, 2020, on any new or existing metering installation that has a monthly average peak demand during a calendar year of over 50 kW; and

Outcome	Investment Benefits and Objectives
	• Enhancing and renewing Alectra Utilities' meter data communication and processing systems to support Time-Of-Use and interval billing. • Ensuring Alectra Utilities' compliance with Measurement Canada requirements (i.e. pursuant to Weights and Measures Act, Electricity and Gas Inspection Act and related regulations) by: • Using certified electrical meters and metering installations to charge a customer for electrical consumption; and • Using our Measurement Canada certified Meter Test Facility to refurbish meters. • Ensuring Alectra Utilities' compliance with IESO requirements by installing, renewing and maintaining metering equipment at wholesale metering points in accordance with IESO Market Rules. • Ensuring Alectra Utilities' compliance with federal PCB Regulations SOR/2008-273 under the Canadian Environmental Protection Act by replacing six metering installations identified as containing greater than 50 mg/kg of PCBs.
Efficiency	Reduce meter reading resource requirements by replacing manually-read meters with remotely-read meters.

III Investment Drivers and Need

3.1 Purpose

As summarized in section 1, the work in the Network Metering portfolio consists of installing and renewing electrical metering assets to serve Alectra Utilities' customers in compliance with applicable obligations, including Alectra Utilities' distribution licence conditions, OEB requirements, Measurement Canada requirements, IESO Market Rules, the Ontario Cyber Security Framework, and federal PCB Regulations. Accordingly, the primary driver of the Network Metering investments is satisfying Alectra Utilities' mandated services obligations.

The planned Network Metering investments are also driven by customer service requests and the failure of current assets.

The primary and secondary drivers are further defined and summarized in Table A01 - 6.

Table A01 - 6: Investment Drivers

Investment Driver	Reasoning and Investment Benefits
Primary Driver: Mandated Service Obligations	• Install and maintain a meter installation for settlement and billing purposes for each customer connected to the distribution system. (DSC, 5.1.1) • Ensure accurate billing by using a certified electrical meter and metering installation to charge a customer for electrical consumption. (Weights and Measures Act, Electricity and Gas Inspections Act and associated regulations) • Install and maintain a MIST meter on every existing installation that has a monthly average peak demand during a calendar year of over 50kW. (DSC, 5.1.3) • Install and maintain IESO compliant metering at all of Alectra Utilities' wholesale metering points. (IESO Market Rules) • Support Time-Of-Use billing for customers with demand of 50kW or less, and interval billing for customers with demand greater than 50kW, by enhancing and renewing meter data communication and processing systems. (DSC) • Remove metering Potential Transformers containing greater than 50 mg/kg of PCBs by end of 2025 (pursuant to PCB Regulations SOR/2008-273 made under the Canadian Environmental Protection Act).
Secondary Driver: Customer Service Requests	• Respond to customer requests to change or upgrade existing meter installations, including concerning meter location, type of metering, or additional functionality to enable access to metering data.
Secondary Driver: Failure Risk	• Replace first generation (iCON F) Sensus residential meters due to cyber-security risk.

IV Investment Timing and Pacing

4.1 Summary of Expenditures

Table A01 - 7 provides the year-over-year breakdown of Network Metering investments, including the historical period from 2015-2018, the bridge year in 2019, and the DSP period from 2020-2024.

Table A01 - 7: Historical and Proposed Investment Spending

	Historical Spending				Bridge	Forecast Spending				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$18.1	$9.4	$12.2	$10.8	$14.3	$14.8	$14.3	$10.2	$11.6	$12.2

4.2 Historical Period Expenditures (2015-2019)

Historical metering investments between 2015 and 2018 total $50.5MM, and the bridge year of 2019 is planned to be $14.3MM. These investments included the renewal of expired and functionally obsolescent meters across the system.

Subject to the annual variances described below, work volumes and associated investments have been relatively consistent year to year from 2014 to 2019. Each year saw the steady continuation of a common set of “baseline” activities (accounting for approximately $9 million in investment per year). This baseline workload consisted of the following:

- Install meters for new services (approximately 15,000 per year)
- Renew metering on upgraded services
- Renew approximately 5,000 failed distribution customer meters per year (does not include planned replacement due to upgrades in cyber-security or meter data communication)
- Refurbish approximately 6,000 meters per year that reach the end of seal life
- Renew wholesale metering installations
- Renew meter data field equipment
- Renew meter data head end and data verification systems
- Renew 5 Meter Potential Transformers (one set per year) that were identified to contain greater than 50 mg/kg of PCB

- Renew and increase tools and testing equipment

In addition to the above, additional activities and investments were also carried out in each historical year, as follows:

2015 - $18.1MM total expenditures

- Renewed 7,000 meters due to identified catastrophic failure risk
- Renewed wholesale metering points at a Transfer Stations
- Installed 2,000 suite meters above baseline demand due to customer demand
- Replaced 4,000 iCON F meters

2016 - $9.4MM total expenditures

- Installed new wholesale metering points at a new Transfer Station
- Replaced 4,000 iCON F meters

2017 - $12.2MM total expenditures

- Renewed 500 Trilliant AMI Gate Keepers to improve meter data communication
- Renewed 350 Elster AMI Gate Keepers to improve meter data communication
- Replaced 5,000 iCON F meters
- Renewed 1,000 SMART meters to improve meter data communication

2018 - $10.8MM total expenditures

- Replaced 8,000 iCON F meters
- Replaced 500 smart meters to improve meter data communication

2019 - $14.3MM planned total expenditures

- Replace 20,000 iCON F meters
- Install 2,500 MIST meters on existing services
- Start of suite meter seal expiry renewal (4,000 suite meters in 2019)
- Renew a meter test board

4.3 Future Expenditures (2020-2024)

Future investments from 2020 to 2024 will total $63.1MM These investments are primarily focused on the replacement of metering equipment for customers and wholesale metering points, and on upgrades to the meter data systems designed to transfer usage data from the meters to the CIS.

Certain baseline workload and associated investment planned for the DSP period are consistent year over year relative to the 2014 to 2017 period. At the same time, future investment related to similar baseline work will increase due to rising material and labour costs and the proportional growth in Alectra Utilities' meter fleet.

For forecasting purposes, the unit costs for workload above the baseline is based on historical unit costs, adjusted for increases in labour and material costs. Meter costs are rising because the overall demand for new meters in Ontario and across Canada is dropping due to LDCs completing their smart- and MIST-meter implementation. The reduction in demand affects the manufacturer's economy of scale, putting increasing pressure on the prices of these meters.

The forecast cost of the Network Metering portfolio over the 2020-2024 DSP period is based on the following drivers:

- Metering for new services
  - Baseline of approximately 15,000 new services per year
  - Costs for baseline work based on historical investment adjusted for inflation
- Installing MIST meters
  - Costs for baseline work based on historical unit costs adjusted for inflation and known number of meters to replace
- Renewing failed meters
  - Costs for baseline work based on historical investment adjusted for inflation, and growth of Alectra Utilities' meter fleet, with baseline of approximately 5,000 replacements per year
- Replacing iCON F meters
  - Costs based on historical unit costs and planned number of meters to replace
- Refurbishing meters that reach end of seal life
  - Baseline of approximately 10,000 refurbishments per year; increased workload due to suite meters

    - Costs for baseline work based on historical investment adjusted for inflation
    - Costs for predicted incremental workload of MIST and suite meters based on historical unit costs adjusted for inflation, and number of meters identified by their seal expiry date
- Renewing wholesale metering installations
    - Costs for baseline work based on historical investment adjusted for inflation
- Renewing meter data field equipment
    - Costs for baseline work based on historical investment adjusted for inflation
- Renewing meter data head end and data verification systems
    - Costs for baseline work based on historical investment adjusted for inflation
- Renewing Meter Potential Transformers that contain greater than 50 mg/kg of PCB
    - One transformer set to be replaced per year
    - Costs for baseline work based on historical investment adjusted for inflation
- Replacing a Meter Test Board and Portable Testing Equipment
    - Costs for baseline work based on quoted price for a test board

The following bullet-points summarize the major planned work above the baseline for each year of the DSP period:

2020 - $14.8MM planned total expenditures

- Replace 26,000 iCON F meters
- Install 1,000 MIST meters on existing services

2021 - $14.3MM planned total expenditures

- Replace 36,000 iCON F meters
- Lower than baseline expired suite meters (-3,000 meters)

2022 - $10.2MM planned total expenditures

- No projects above baseline
- Lower than baseline expired suite meters (-3,000 meters)

2023 - $11.6MM planned total expenditures

- Renew a higher number of C&I meters with expired seals

2024 - $12.2MM planned total expenditures

- Renew a higher number of C&I meters with expired seals

4.4 Investment Pacing and Prioritization

In order to remain in compliance with the applicable legal and regulatory regimes, the investments that support mandated service obligations must be executed on the year they are planned. None of this work can be moved to later years.

Alectra Utilities plans to replace the obsolete Sensus iCON F meters by 2021 based on the need to eliminate this risk in a timely fashion. The pace of the work is higher at the end of the program to minimize the value of the scrapped meters.

Alectra Utilities plans to replace the Meter Potential Transformers containing PCBs at a rate of one unit per year until 2024 in order to satisfy the regulatory requirement that all such units be removed from the utility's system by December 31, 2025.

4.5 Execution Approach

Alectra Utilities will leverage internal and external contractors to complete the design and construction of the new underground infrastructure to be installed within the system. Alectra Utilities has retained external contractors working at different work sites throughout the year under a multi-year engineering procurement construction ("EPC") Master Service Agreement. Regular progress meetings are held to ensure technical and operational issues are resolved promptly. The Execution phase will follow Alectra Utilities' internal project management methodology which provides specific guidelines, procedures, work instructions, and industry best practices that allow the project work to be performed in an economically efficient, cost-effective, and safe manner.

The work required in each year will be completed in each year. The projects deliver mandated service obligations or are required to reduce the risk of spills. The work may by reprioritized within each year, as required by the demands of unplanned work that is driven by customer service requests and failure of equipment.

Alectra Utilities will control costs and manage unpredicted workload by using existing outside service providers. This flexibility allows Alectra Utilities to make the best use of our internal resources.

Some tasks that can currently be done by outside service providers are:

- Installing residential socket and multi-unit (suite) meters
- Replacing failed residential socket and multi-unit (suite) meters
- Changing residential socket and multi-unit (suite) meters as part of our meter seal refurbishment program
- Installing MIST meters on existing services
- Assisting in the Measurement Canada certified Meter Test Shop
- Assisting with assembly of Meter Data Communication Data Collectors
- Project Manage multi-unit (suite) meter new and retro-fit building projects

Alectra Utilities will assess the need to replace retiring staff based on actual workloads and productivity gains from new tools, and practices. If there are short-term periods where workload exceeds those tasks that are done exclusively by our internal staff, Alectra Utilities will explore the opportunity to expand the tasks done by outside service providers.

V Options Analysis

When preparing the Network Metering portfolio Alectra Utilities considered alternatives under which the utility would either maintain the status quo (i.e., not carry out the work), or make investments using alternate delivery and timing methods.

5.1 Status Quo / Do Nothing

Most of the investments support mandated service obligations, compliance with Measurement Canada regulations, alignment with the Ontario Cyber Security Framework, compliance with the PCB Regulations, as indicated within the program descriptions:

- Annually installing metering equipment for an estimated 15,000 new services;
- Annually replacing approximately 5,000 meters and other metering equipment that fail;
- Annually installing approximately 250 MIST meters and communication equipment on services with monthly demand that exceeds 50kW;
- Enhancing and renewing meter data communication and processing systems to support accurate and timely customer billing
- Renewing 5 metering potential transformers containing PCB's
- Renewing 91,000 meters that do not align with the Ontario Cyber Security Framework

The status quo option, not execute the work, means that Alectra Utilities will not fulfill its regulated obligations, and will fail to comply with other regulations listed above. As a consequence, the following will occur in the short term:

- No new customer services energized or metered.
- Customers not satisfied with level of customer service on requests to change metering installations.
- Growing number of existing customers with estimated bills.
- Billing a growing number of customers based on data from electrical meters and metering installations not approved for this use by Measurement Canada.
- Billing a growing number of customers based on inaccurate meter data.
- Growing number of Wholesale metering points not sending data to IESO.

From a long-term perspective, the following negative consequences will occur (specific timeline depends on the consequence):

- OEB order to comply with Alectra Utilities' distributor's license.
- Order to Comply by from the IESO.
- Orders to Comply and escalating fines from Measurement Canada for using unapproved meters to bill customers.
- Complaints on inaccurate bills, chronically estimated bills, and poor customer service from customers.
- Spill of PCB contaminated materials into the environment.
- Illegal access to customer information.
- Complaints and non-compliance issues escalated to the municipal and provincial political level, and featured in the media.
- Loss of reputation with customers, shareholders, regulators and electrical distribution industry.

5.2 Alternative Delivery Options

For some elements of the Network Metering investments, there may be alternate delivery options for Alectra Utilities' Network Metering investments. For each alternative, the sections below summarize Alectra Utilities' plan as reflected in the sections above, the alternative approach, and the consequences of selecting that alternative:

5.2.1 Renew Single Phase Self-Contained Meters / Renew iCON F Meters

DSP Plan: carry out 100% of the field work with contract staff; complete the work by the end of 2021

Alternative Approach: carry out field work with internal staff and delay the work to after 2021

- Inside staff would work on overtime; no capacity during regular hours – investment increases by 30%
- Cost of meters will increase substantially after 2021

5.2.2 Install MIST meters on existing services

DSP Plan: carry out >80% of the field work with contract staff
Alternative Approach: carry out field work with internal staff

- Inside staff would work on overtime, no capacity during regular hours – investment increases by 6%

5.2.3 Renew Commercial and Industrial Meters

DSP Plan: carry out field work with internal staff in regular hours
Alternative Approach: carry out field work with contract staff

- Project investment increases by 28%

5.2.4 Renew Meter Seal Expiry / Purchase Meter Test Board:

DSP Plan: carry out meter testing at internal facility
Alternative Approach: carry out meter testing at an outside shop

- Outside profit and shipping added to cost - investment increases by 25%

5.2.5 Enhancing and renewing meter data communication systems:

DSP Plan: carry out work to keep systems operating to deliver data to billing system
Alternative Approach: delay renewal of systems for 1 year

- Increased costs for manually reading meters 1% of fleet (10,000 meters) for 1 year – operating costs increases by $0.2MM

VI Investment Projects

The material investments from 2020 to 2024 that form the Network Metering investments are included in Table A01 - 8.

Table A01 - 8: Material Projects and Initiatives

Project Code	Project Name	CAPEX ($MM)
150648	All Metering Capital (but Suite) - Central South	$11.6
150620	Meter Capital - all account types - West	$10.3
150605	Residential Meter "iCON F" Meter Replacement	$7.3
150664	Replace Faulty Residential Meters by Lines - Central North	$4.0

Appendix A02 - Customer Connections

I Overview

Investments in the Customer Connections category are connections, modifications or realignments to the distribution system that provide Alectra Utilities' customers with access to electricity. All of the work in the Customer Connections portfolio is mandatory, as it is required to satisfy the conditions of Alectra Utilities' license and the Distribution System Code (DSC).There are five types of investments in this category, each of which is summarized below:

- Layouts;
- New Services;
- New Subdivisions;
- Renewable Generation; and
- Customer Initiated Distribution System Projects.

Layouts

Layouts consist of work to make the system ready for new residential infill services, and upgrading residential services and small commercial services. A layout is typically is comprised of a single page drawing with sufficient detail to provide crews or contractors the information to construct the service. It also includes a cost estimate that is provided to the customer for design, materials and construction of the service. A layout is provided to each customer at a given location. The customer's service could be underground or overhead and is the connection from the main plant on the boulevard to the building. Costs are shared between the customer and Alectra Utilities in accordance with the DSC and Alectra Utilities' Conditions of Service. This includes the provision of a basic connection allowance for each residential service. This basic connection credit equates to 30m of an overhead service and 10m of an underground service.

New Services

New Services consists of new and/or upgraded primary services to industrial, commercial and institutional customers (such as medical buildings, small plazas or factories). A New Service typically consists of a Work Order being issued with complete drawings and work instructions and an Offer to Connect (OTC). These services are normally underground from the existing distribution or sub-transmission system and up to and including the padmount transformer. Customers contribute 100% of the cost for new services. These are also known as Commercial, Industrial and Institutional (ICI) services.

New Subdivisions

New Subdivisions expenditures consist of the primary and secondary underground cables as well as transformers installed to the street line of each lot within a new residential "Greenfield" subdivision development. In accordance with the DSC, the development cost is put through an economic model to determine the LDC share and the Developer share based on revenues from the development. A new subdivision consists of an OTC that prescribes the responsibilities and cost sharing of both parties. These developments are based on Alectra Utilities-approved materials, standards and specifications. An approved drawing and work instruction package are issued for construction to initiate the project.

Renewable Generation

Renewable Generation investments are connections to the distribution system that add to capacity to the system that are not supplied by the transmitter. These included the feed-in-tariff (FIT) programs, micro-FIT programs, biogas facilities, wind generation, solar, co-generation, battery storage, combined heat and power or other evolving technologies. The investments requirements are Alectra Utilities' requirements as prescribed by the DSC.

Customer Initiated Distribution System Projects

Customer Initiated Distribution System Projects are typically system expansions or distribution system relocations. System expansion usually occurs when Alectra Utilities does not have existing or adequate supply to a proposed development. System relocations are usually initiated by homeowners or developers that have a conflict with a component of the distribution system or do not like the aesthetics of the existing system components relative to their properties.

The forecast Customer Connections capital investments are based on planned developments in the communities that Alectra Utilities serves, historical trends, and other known projects. Alectra Utilities' forecast investments are based on a range of information including historical data, continual communications with developers, reviewed subdivision applications, regional reports on future residential growth, municipal reports on growth management, residential intensification assessments, reports, interest and mortgage rates as well as government incentives or conditions.

Alectra Utilities works to ensure that the necessary resources are available to execute the forecast Customer Connection work. Through a competitive Request for Proposal (RFP) process, Alectra Utilities has coordinated with civil contractors to ensure that construction resources are ready to support future developments. Alectra Utilities will complete projects in a timely manner and in accordance with the utility's construction and material standards

Alectra Utilities participates during the preliminary stages of project planning with developers, city planners and civil consultants. This ensures that Alectra Utilities can provide comments and recommendations with respect to the distribution system prior to final designs being implemented. This approach produces efficient and cost-effective designs.

Table A02 - 1: Investment Subgroup Summary

	Historical Expenditure				**Bridge**	**Forecasted Expenditure**				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$33.3	$31.8	$26.9	$25.2	$34.7	$31.4	$33.1	$34.8	$36.3	$37.7
Primary Driver:	Customer Service Requests									
Secondary Drivers:	Mandated Service Requirements									
Outcomes:	Customer Value, Reliability, Safety, Coordination and Interoperability, Environment, Efficiency.									

II Investment Description

Customer Connections investments are essential in order to meet the demand to connect customers to Alectra Utilities' distribution. The program also includes any additional expansions or enhancements to the system for connections where Alectra Utilities is required to make an OTC.

The assets that make up Customer Connections expenditures vary with the circumstances of each connection. In new greenfield or brownfield subdivision developments, installation of new Alectra Utilities infrastructure, including primary and secondary underground cables, as well as padmounted transformers and pole terminations, will be necessary in order to provide necessary electrical supply. The constructed design within each subdivision will account for existing and continued development in the area. Alectra Utilities presents an OTC to developers which outlines Alectra Utilities' and the developer's responsibilities for new subdivision developments. An economic analysis is completed to determine developer costs versus Alectra Utilities' costs. For residential subdivisions, the final economic analysis is based on the number of services connected within a five-year window.

The design of customer connections must follow Alectra Utilities' current standards. As an example, new residential subdivisions are installed in a "looped supply" configuration, with fault indicators installed at each transformer, underground switch and riser pole, to ensure that restoration procedures can occur as efficiently as possible should any asset fail in the future. Designs also incorporate planning criteria to mitigate overloading of installed circuits considering new and pending developments. Phasing of Developments is strategically planned and scheduled to ensure Developments are energized from one phase to the next with minimal interruption to existing customers. Designs that incorporate these items allow for safe and reliable delivery of electricity while ensuring additional customers can be accommodated as the systems expands to meet new development needs.

For Industrial, Commercial and Institutional ("ICI") customers, supply at the demarcation point can be either at the secondary or primary voltage levels, through either a utility-owned transformer providing secondary voltage to a single building or group of buildings or connection to a customer-owned transformation. The distribution system to individual customers within the building(s) is not part of utility's assets as it is past the demarcation point.

As noted in section I – Overview above, Customer Connections expenditures are required to meet legal and regulatory requirements for Alectra Utilities and other Ontario electricity distributors.

The *Electricity Act* requires Alectra Utilities to connect a building to its distribution system if:

a) the building lies along any of the lines of the distributor's distribution system; and
b) the owner, occupant or other person in charge of the building requests the connection in writing.[69]

Completing the Customer Connections are a regulatory requirement for Alectra Utilities. These non-discretionary investments maintain compliance with Section 6 of the DSC, in which states that "[a] distributor shall make every reasonable effort to respond promptly to a customer's request for connection." Performing these connections as mandated is a requirement of Alectra Utilities' licence. Alectra Utilities is required to complete connections to customers within five business days as per the DSC, provided that all service conditions are satisfied or agreed to by the customer and Alectra Utilities.

In order to execute this work, Alectra Utilities communicates and coordinates with various city and planning groups such as the municipalities' Public Utilities Coordinating Committees. Alectra Utilities also has discussion with the municipalities once upcoming and proposed developments are identified. Developers ultimately contact Alectra Utilities following approval of their subdivision draft plan applications in order to confirm their electrical servicing requirements.

The following sub-sections provide some of the development trends and specific development projects that Alectra Utilities will need to connect during the term of the DSP in the utility's various geographic regions.

[69] *Electricity Act, 1998, S.O. 1998, c. 15, Sched. A*, s. 28.

2.1 West Customer Connection Developments

Pier 8 is an upcoming urban waterfront community within the City of Hamilton which will combine commercial, condominium, live-work units and townhomes into a single community, with a total of 1,296 units. Connections are anticipated as shown in Table A02 - 2.

Table A02 - 2: Pier 8 Customer Connections

	2019	2020	2021	2022	2023	2024
Number of Units	0 Civil Works Begin	200	250	350	350	146

Alectra Utilities has begun preliminary discussions with Developers and Consultants in reviewing the proposed development to ensure electrical infrastructure designs meet Alectra Utilities' planning and design guidelines.

The City of Hamilton continues to process development applications. In addition, as per the City of St. Catharines Official Plan, approved July 27, 2018, St. Catharines growth forecasted additional households of 7,190 units from 2011 to 2031, with approximately 1800 units added within the DSP horizon. Refer to Table A02 - 3.

Table A02 - 3: St. Catharines Additional Units

	2011	2016	2021	2026	2031	NET GROWTH
Households	56360	58350	60410	62130	63550	7190

The above chart identifies potential growth within St. Catharines. Final growth forecasts for the Region of Niagara and local municipalities remain to be formalized.

Figure A02 - 1: Pier 8

2.2 Centre-North Customer Connection Developments

The City of Brampton has seen a reduction in service connections in 2018 compared to 2017 year over year. Market conditions, mortgage stress test, and affordability of homes has slowed building construction. A slowdown in the City approval process has also delayed deployment of projects within the Brampton territory. To date, Alectra Centre-North operating area has received development applications totalling over 5,000 future units.

The City of Brampton Growth report, prepared by Glen Schnarr and associates, forecasts the north-east areas of Brampton as seeing the bulk of new developments over the DSP horizon.

Unit counts per year have been adjusted to account for the decrease in residential Developments within the Alectra North operating area, specifically in 2018 year over year service connections were down 56%. The introduction of the mortgage stress test, higher interest rates and housing affordability has resulted in lower forecasted numbers from 2019 to 2024 in Alectra Central North operating area compared to 2017 Refer to Table A02 - 4.

Table A02 - 4: Brampton Additional Units

	2019	2020	2021	2022	2023	2024
New Services	2000	2100	2300	2350	2200	2100

The Region of Peel and City of Brampton have scheduled road widening and infrastructure projects in anticipation of new Development within the aforementioned areas. Scheduling of their works is shown on the provided Region and City of Brampton Capital maps. Refer to Figure A02 - 2.

Figure A02 - 2: City of Brampton Roads Capital Program (2018 - 2028)

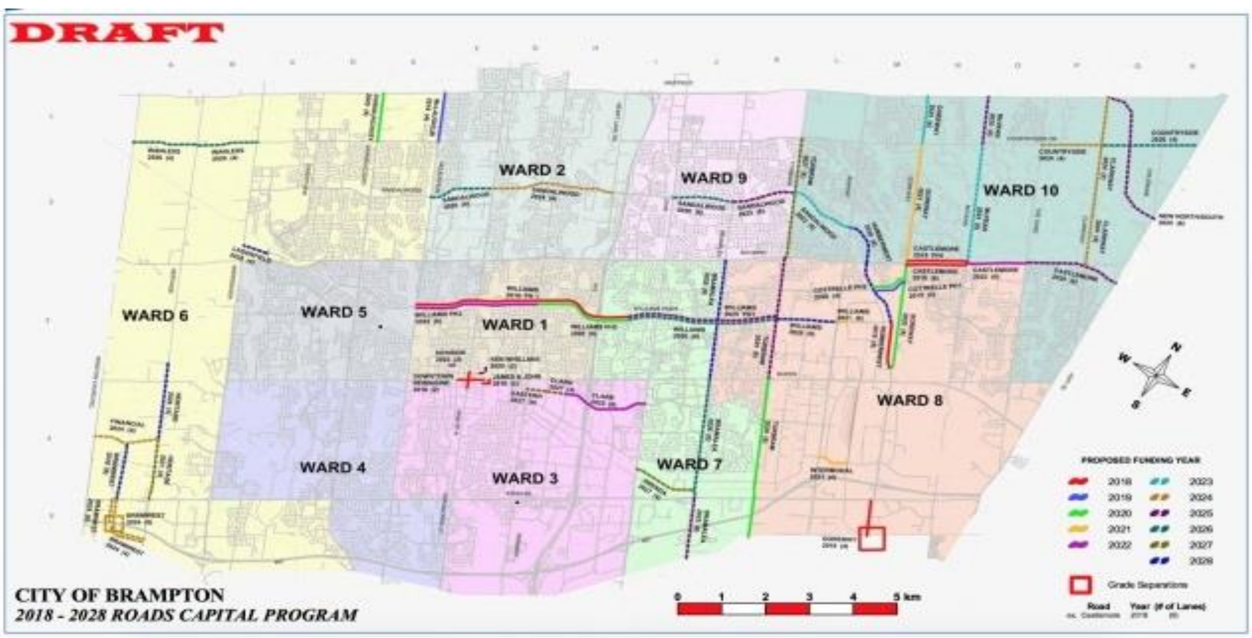
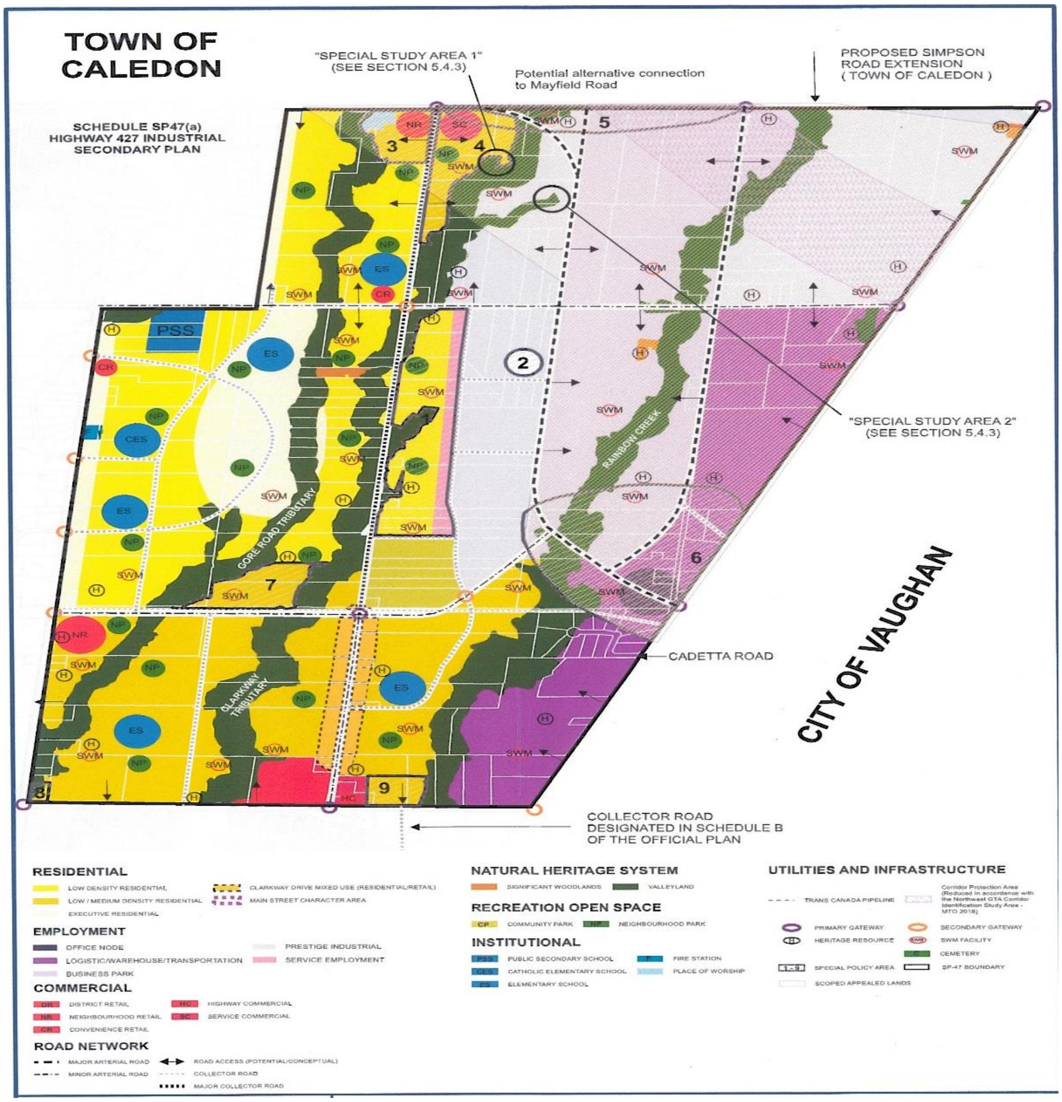


Figure A02 - 3: Northeast Areas of Brampton Development



2.3 Centre-South Customer Connection Developments

Two major projects with Alectra Utilities Centre-South operating area are included in the DSP. The first is Lakeview Estates, which is a multi-phase development with new high-rise and residential units, with a total of 8,000 new units to be developed. The DSP also reflects work to connect the Port Credit West Village, which is a similar multi-phase development with a total of 2,500 units, with approximately 500 townhomes and 2,000 condominium units. Retail and commercial space is also supported within this development Refer to Table A02 - 5 for the anticipated servicing for Lakeview and Pier 8 combined.

Table A02 - 5: Mississauga Additional Units

	2019	2020	2021	2022	2023	2024
New service	Site works to begin	200 Deep Servicing	650	1000	1100	300

Figure A02 - 4: Lakeview Development

Figure A02 - 5: Port Credit

2.4 East Customer Connection Developments

Alectra Utilities' eastern operational area includes the municipalities of Alliston, Aurora, Barrie, Beeton, Bradford, Markham, Penetanguishene, Richmond Hill, Tottenham and Vaughan. Alectra Utilities East is poised for continued growth within the next 6 years and beyond.

York Region's 2041 Preferred Growth Scenario has forecasted, on average, 5,500 new units per year. This includes a mixture of singles, semis, rows and duplex homes. Developments applications within each municipality continue to add growth within York Region. Aurora, Barrie, Markham and Richmond Hill anticipate growth within this time line.

Alectra Utilities East is home to multiple Urban Growth Centre Developments. Two of the major projects during this plan are the Vaughan Metropolitan Center ("VMC") and the Langstaff Gateway Development

2.4.1 VMC Development:

The site provides approximately 179 hectares (442 acres) of development opportunities, it includes:

- 1.5 million sq.ft. of office space, at minimum
- 750,000 sq.ft. of retail space
- 12,000 residential units to be home to 25,000 people
- Density targets of 200 people and jobs per hectare by 2031
- Employment targets of 11,500 jobs of which 5,000 will be new office jobs

Figure A02 - 6: Vaughan Metropolitan Centre

The Langstaff Gateway Development is anticipated to generate 24,900 employment opportunities and add 23,500 residential units. High Density residential, Office and retail space with integrated transit infrastructure.

Figure A02 - 7: Langstaff Development

2.5 Southwest Customer Connection Developments

Alectra Utilities Southwest includes the municipality of Guelph and Village of Rockwood. The City of Guelph has seen an increase in high density housing over the last few years and this is evident with numerous planned condominium developments within all areas of the City totaling over 2,500 units in the next few years. In addition, there are more than 1,500 residential units planned for construction over the next six years (2019-2024) in various subdivisions across the city.

The City of Guelph is in the process of developing a detailed secondary plan for Clair Rd to Maltby Rd proposing a corridor of high-density housing on Gordon St and surrounded with low/mixed density subdivisions and commercial sections as the city expands to its existing boundaries. The City of Guelph also has a secondary plan in place for the Guelph Innovation District which have identified a population target of 6,600 with an estimated 2,150 units.

Figure A02 - 8: Gordon St. Development

2.5 Metrolinx Developments

The customer connections investment will also include projects to connect intra-city or inter-city transit electrical infrastructure to the distribution system, as noted in Table A02 - 6.

Table A02 - 6: Summary/Status of Metrolinx Known Projects

Project	Time Period	km of Project	Description - location
Hamilton LRT	2019-2024	14km	Between Cootes Drive at McMaster University, east along Main Street West, crosses 403 to King Street. Travels east along King Street until the intersection with main Street. Travels east along Main Street until Eastgate Mall.
Hurontario-Main LRT	2019-2022	22km	Between Port Credit GO Station, north on Hurontario Street to Steeles Road in Brampton. Loops around Square One on Burnhamthorpe between Hurontario and Duke of York, on Duke of York between Burnhamthorpe and Rathburn, and on Rathburn between Duke of York and Hurontario.
-Barrie Go Train Enhancements -Go Electrification - Markham/Stouffville 2 Way All Day Go Train	End of 2021		Relocation of approximately 89 conflicts along the Barrie, Stouffville, Kitchener and Lakeshore West GO Rail Corridors.
Brampton Queen St Rapid Transit	Subject to government funding and approval.		No definitive boundaries established
Dundas Street BRT	Subject to government funding and approval.		No definitive boundaries established
Hamilton/Aldershot 2 Way All Day Go Train	Subject to expropriation issues between Metrolinx and CN.		No definitive boundaries established

These large urban centric Metrolinx projects are expected to either sustain current growth patterns or increase them significantly in the residential and ICI sectors over the reporting period. This expectation is based on the text that is on the Metrolinx website:

> *Metrolinx is undertaking the largest transportation investment in Ontario's history to get you where you need to go better, faster, easier, while also operating GO Transit, UP*

> *Express and PRESTO. We have a unique opportunity to plan, build, operate and connect transportation in the Greater Toronto and Hamilton Area.*
>
> *When the Province of Ontario created Metrolinx as a new regional transportation agency in 2006, the challenges of under-investments in transit were mounting. Metrolinx was tasked to work with federal, provincial and municipal partners, the private sector and other stakeholders to create an integrated transportation system that would support a higher quality of life* ***, a more prosperous economy*** *and a healthier environment.*
>
> *And our growth continues. Today, the expansion of transit in the Greater Toronto and Hamilton Area is one of the largest concentrations of infrastructure projects in North America. By 2041, more than 10 million people will live in our region—comparable to Paris or London. Metrolinx continues working towards delivering an integrated, regional transportation system with a mix of buses, streetcars, light rail, heavy rail and subways* ***that will serve the needs of residents and businesses for years to come****. With the release of the 2041 Regional Transportation Plan, we are mapping out our future vision of how we plan to connect communities and cities.*
>
> *Our region is growing quickly, and we must continue the work underway to ensure that people can get to where they need to go, today and in the future.*
>
> *The 2041 Regional Transportation Plan – the 2041 RTP - is about providing even more people with access to fast, frequent and reliable transit, and making it easier for travellers to use transit, or travel by bike or on foot.*
>
> *The 2041 RTP guides the continuing transformation of the transportation system in the Greater Toronto and Hamilton Area (GTHA). It is the blueprint for an integrated multimodal regional transportation system that puts the traveller's needs first.*

In addition, there have been and will be significant investments by the Toronto Transit Commission ("TTC") and York Region Transit ("YRT") based on the following projects:

- VivaNext (YRT) (2019-beyond):
  - Yonge, Major MacKenzie, Steeles, Leslie, Jane
- Yonge Subway Extension (TTC)

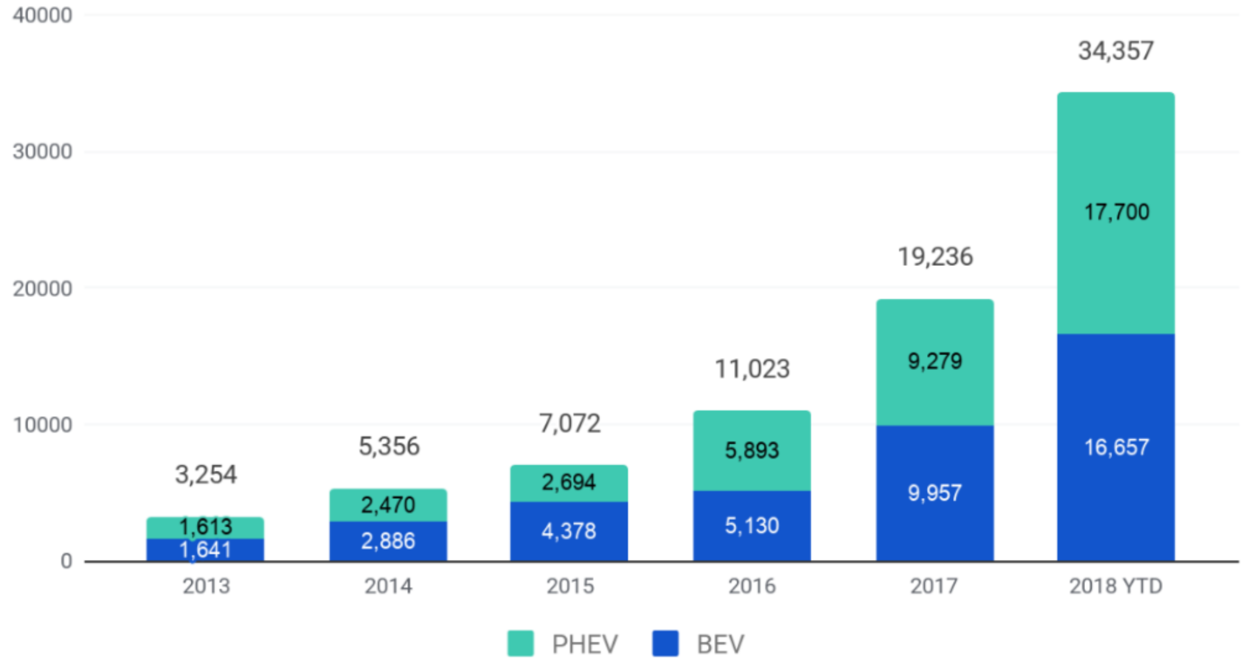
Figure A02 - 9: VivaNext

Predicted uptake for development along the corridors of the Metrolinx projects is approximately 25 institutional projects for the first three years of the reporting period and then tapers off in the latter three years in terms of rate of increase in projects.

2.6 Electric Vehicle ("EV") Charger Upgrades

This investment will include upgrades to account for electric vehicle chargers across Alectra Utilities' service territory. Electric vehicles will continue to become a vehicle of choice as technology and affordability increase. Refer to Figure A02 - 10 for recent sales data.

Figure A02 - 10: Annual Canadian EV Sales[70]



Year	2013	2014	2015	2016	2017	2018 YTD
BEV	1,641	2,886	4,378	5,130	9,957	16,657
PHEV	1,613	2,470	2,694	5,893	9,279	17,700
TOTAL	3,254	5,356	7,072	11,023	19,236	34,357

Single residential units that install EV chargers will do so through the layout process. Upgrades to commercial facilities or condos, where there are 3 phase transformers, will have requests through the ICI process, as these involve metering upgrades and possibly transformer replacements, as was the case in 2018.

[70]"Electric Vehicles Sales Update Q3 2018, Canada" fleetcarma, Nov 6, 2018. URL: https://www.fleetcarma.com/electric-vehicles-sales-update-q3-2018-canada/

2.7 Customer Initiated Distribution System Projects

Customer Initiated Distribution System projects typically consist of system expansions or distribution system relocations when Alectra Utilities does not have existing or adequate supply to a proposed development. System relocations are usually initiated by homeowners or developers that have a conflict with a component of the distribution system or do not like the aesthetics of the existing system components relative to their properties.

In accordance with the DSC, distributors are required to connect customers who require power and where necessary, a distributor may need to expand its distribution system to allow for the connection of new customers or existing customers who require increased capacity. Examples of these include new feeders to supply Juranviski Hospital and the Beach road expansion. These projects require work on the distribution system as a result of a customer's needs.

2.8 Summary of Investment Outcomes and Benefits

Table A02 - 7 summarizes the outcomes and benefits associated with the Customer Connections investment.

Table A02 - 7: Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Efficiency	• All subdivision projects are coordinated with system planning to ensure optimal coordination of capacity supply • Alectra Utilities coordinates with other utilities to ensure the most cost-effective installation is achieved. New developments incorporate joint use trench, which includes electric, gas, telephone and TV.
Customer Value	• Ensures that Alectra Utilities continues to meet its customer service objectives (e.g. customers continue to be connected within five business days as mandated by the DSC.) • Ensures that customers receive an appropriate supply based upon their usage requirements.
Reliability	• Current standards and designs improve reliability and Alectra Utilities' response to an outage event.
Safety	• Current standards and procedures ensure safety risks are mitigated.
Co-ordination / interoperability	• Alectra Utilities coordinates future supply requirements in conjunction with City Road widening projects to ensure assets are in place ahead of development projects. When development is ahead of new road construction, Alectra Utilities will schedule Capital projects to extend primary supply to new developments.
Environment	• Project designs adhere to Toronto and Region Conservation Authority and Ministry of Natural Resources and Forestry requirements when constructing in environmentally sensitive areas. • Proper approvals and permits are obtained before constructing along or crossing creeks or rivers. Endangered species act will also dictate design and scheduling requirements to remove risk to species.

III Investment Drivers and Need

3.1 Purpose

The primary driver of this investment is customer service requests that require expansion and/or connection to Alectra's Utilities' distribution system and service upgrades for existing customers. The secondary driver is Alectra Utilities' statutory obligations to connect new and existing customers to its distribution system. These investments are essential in order to meet the demand of connecting connections to the distribution system.

Table A02 - 8: Investment Drivers

Investment Driver	Reasoning and Investment Benefits
Primary Driver: Customer Service Requests	These investments are required to connect customers to the distribution system.
Secondary Driver: Mandated Service Requirements	These investments are required to comply with the legislative and regulatory requirements including the DSC, Electricity Act and conditions of Alectra Utilities' license.

Overall, Alectra Utilities expects development to trend upward across the utility's service territory from 2019 to 2024. *"Places to Grow, Growth Plan for the Greater Golden Horseshoe*" [[71]] is a government initiative to plan for growth and development. One of the "Guiding Principles" was to prioritize *intensification* and higher densities to make sufficient use of land and infrastructure and support transit viability. The various municipalities have updated their growth plans to meet the requirements of the government initiative. Proposed Amendments to the plan "are intended to address potential barriers to increasing the supply of housing, creating jobs and attracting investments."

Table A02 - 9 illustrates both the historical and forecasted quantities of customer connections (2015 to 2024) in Subdivisions, ICI, Layouts, New Secondary Services and Renewable Generation. Figure A02 - 11 shows the trending for each type of new connection: of note is that

[71] "Growth Plan for the Greater Golden Horseshoe", Ontario Ministry of Municipal Affairs and Housing, 2017, URL: http://placestogrow.ca/index.php?option=com_content&task=view&id=430&Itemid=14

subdivisions peak in 2020, then decline, ICIs increase annually and layouts have a steady annual increase. The microFIT and FIT programs ended in 2018; this results in the drop in expected connections of this type.

Table A02 - 9: Number of New Connections 2014-2024

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Number of New Subdivisions (lots)	12226	12023	11368	9640	8250	8775	9400	9350	8575	8400
Number of ICIs	466	524	490	431	471	511	538	552	567	582
Number of Layouts	7981	7523	8194	7133	7447	7493	7520	7631	7745	7861
Number of RGEN connections	n/a	827	929	882	130	224	272	199	142	108

Figure A02 - 11: New Connections: 2015-2024

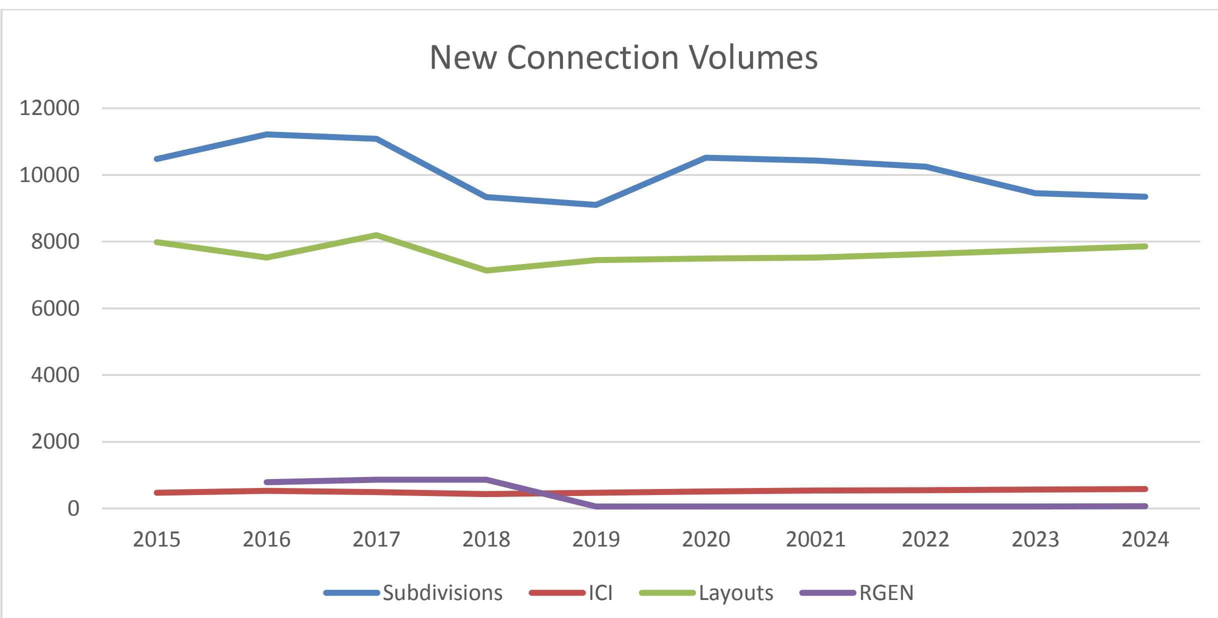


Table A02 - 10 illustrates the expected population and household growth across the four major Alectra Utilities' rate zones from 2016 onwards to 2041. These results indicate that an average population growth of 41.7% and an average household growth of 44.0% respectively can be expected to occur between now and 2041. Figure A02 - 12 illustrates these rates of growth. New housing developments are anticipated to continue within Alectra Utilities' service territory as demand for homes/ dwellings will continue in support of the increased population growth.

Figure A02 - 12: Population Growth Rates

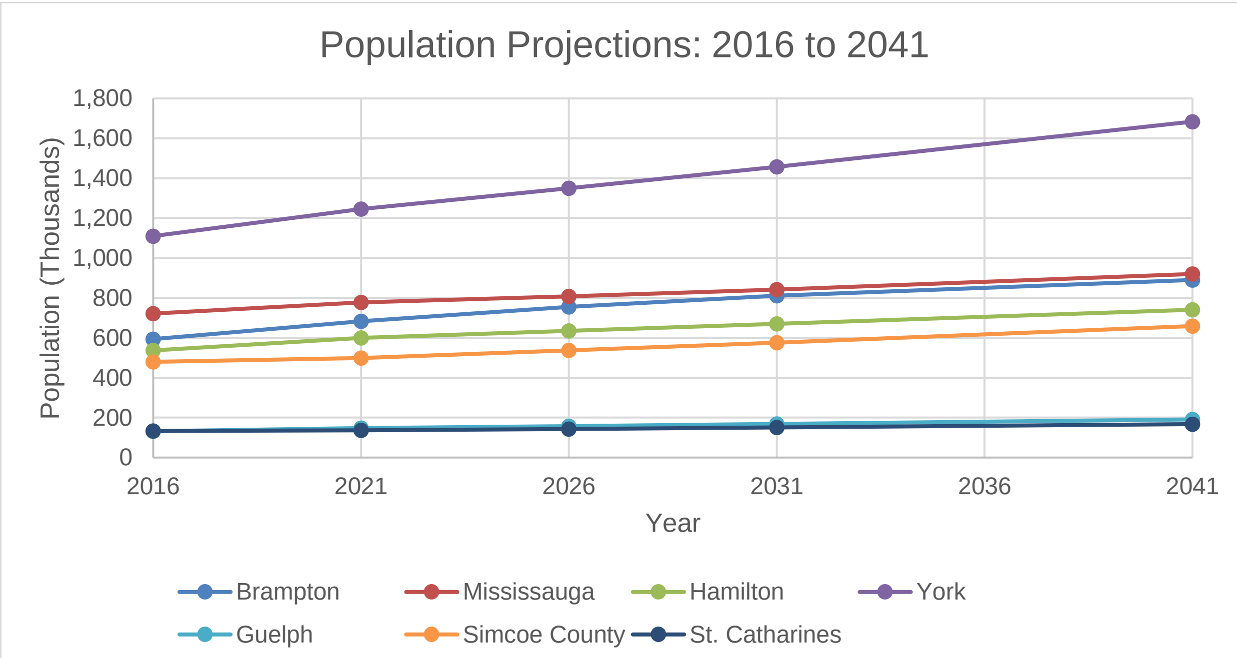


Table A02 - 10: Population and Household Growth Forecast – 2016-2041

Year	Measure	Brampton	Mississauga	Hamilton	York	Guelph	Simcoe County	St. Catharines
2016	Population	593,638	721,599	536,917	1,109,909	131,794	479,650	133,113
	Households	168,010	240,910	216,325*	366,160*	52,090	173,310	57,020
2021	Population	683,700	777,730	599,400	1,245,900	148,000	499,000	136,930
	Households	189,520	252,230	228,850	408,880	59,200	194,300	58,330
2026	Population	755,710	808,260	634,300	1,349,200	158,000	537,000	142,560
	Households	210,860	265,660	245,645*	451,625*	63,200	216,030	59,720
2031	Population	811,970	842,070	669,900	1,457,400	169,000	575,000	150,590
	Households	227,610	279,140	262,450	494,380	67,600	236,760	61,120
2041	Population	890,000	920,020	740,700	1,683,600	191,000	659,000	167,480
	Households	250,460	307,470	298,400	559,160	76,400	281,500	
% Increase Population		49.92%	27.50%	37.95%	51.69%	44.92%	37.39%	25.82%
% Increase Households		49.07%	27.63%	37.94%	52.71%	46.67%	62.43%	7.19%**

Notes:	
*	This data is estimated by linear interpolation using available data
**	This percentage is based on households in 2031
1.	**All Population data for 2016 comes from**: "Census Profile, 2016 Census", Statistics Canada. URL: https://www12.statcan.gc.ca/census-recensement/2016/dp-pd/prof/index.cfm?Lang=E
2.	**Brampton and Mississauga Population (2021-2041) and Housing (2016-2041) Data:** "Region of Peel Housing Strategy", SHS Consulting, July 2018, URL: https://www.peelregion.ca/planning/officialplan/pdfs/2018/2018-housing-strategy.pdf
3.	**Hamilton and York Population (2021-2041) Data:** "Ontario Population Projections Update, 2017-2041", Ontario Ministry of Finance, 2018, URL: https://www.fin.gov.on.ca/en/economy/demographics/projections/

4.	**Hamilton and York Housing (2016-2041) Data:** "Greater Golden Horseshoe Growth Forecasts to 2041", Hemson Consulting Ltd., June 2013, URL: https://www.hemson.com/wp-content/uploads/2016/03/HEMSON-Greater-Golden-Horseshoe-Growth-Forecasts-to-2041-Technical-Report-Addendum-and-Rev.-Appendix-B-Jun2013.pdf
5.	**Guelph Population (2031) Data:** https://guelph.ca/business/economic-development-office/guelph-quicksheet/ 2031 Projected Population = 169,000
6.	**Guelph Population (2041) Data:** http://placestogrow.ca/index.php?option=com_content&task=view&id=430&Itemid=14 2041 Projected Population = 191,000
7.	**Guelph Housing (2016) Data:** https://www12.statcan.gc.ca/census-recensement/2016/dp-pd/prof/details/page.cfm?Lang=E&Geo1=CSD&Code1=3523008&Geo2=CD&Code2=3523&Data=Count&SearchText=Guelph&SearchType=Begins&SearchPR=01&B1=All&TABID=1 2016 Number of Households = 52,090
8.	**Guelph Population (2021-2041) and estimated Housing (2021-2041) Data:** http://guelph.ca/wp-content/uploads/ 2012CommunityProfile.pdf Avg. No. of people per household = 2.5 is used to calculate the future projections based on this report.
9.	**St. Catharines Population (2021-2041) Data:** "How We Grow – Niagara 2041", Niagara Region, URL: https://www.niagararegion.ca/2041/pdf/mcr-pic3-boards.pdf
10.	**St. Catharines Housing (2016-2031) Data**: "Table 4-1: Niagara Region, Population, Household and Employment Forecast by Local Minicipality, 2006 – 2031", Niagara Region, URL: https://www.niagararegion.ca/living/icp/pdf/2015/Table-4-1.pdf
11.	**Simcoe County Population (2021-2041) and Housing (2016-2041) Data**: "Greater Golden Horseshoe Growth Forecasts to 2041", Hemson Consulting Ltd, Nov. 2012, URL: https://hemson.com/wp-content/uploads/2016/03/HEMSON-Greater-Golden-Horseshoe-Growth-Forecasts-to-2041-Technical-Report-Nov2012.pdf
12.	York Region- Numbers indicated are for the entire York Region. Alectra Utilities service territory includes Markham, Vaughan, Richmond Hill and Aurora.
13.	Simcoe County –Numbers indicated are for the entire Simcoe County region. Alectra Utilities service territory includes Barrie, Bradford, Thornton, Alliston, Beeton, Tottenham and Penetanguishene.

Table A02 - 11 and Table A02 - 12 respectively provide population and employment increases in percentage, which further provide insight into the growth patterns within Alectra Utilities' service territory and where customer connections activities are forecasted to take place. The data displayed in Table A02 - 11 indicates a decrease in the rate of growth in the various areas from 2021 to 2041, however, the rates during the DSP horizon are expected to be constant as shown. Population and employment increases lead to new subdivision construction and ICI developments.

Table A02 - 11: Population Increases (in %) by Cities/Regions

City/Region	Population (% Increase from Previous Five Years)[72]							
	2006	2011	2016	2021	2026	2031	2036	2041
Peel Region	17%	12%	6%	19%	9%	8%	7%	7%
City of Hamilton	3%	3%	3%	12%	6%	6%	5%	5%
York Region	22%	16%	7%	12%	8%	8%	8%	7%
City of Guelph	8%	6%	8%	9%	9%	8%	7%	6%
Simcoe County	12%	10%	8%	4%	8%	7%	7%	7%
City of St. Catharines	1%	0%	1%	3%	4%	6%	6%	5%

Table A02 - 12: Employment Increases (in %) by Cities/Regions

City/Region	Employment (% Increase from Previous Five Years)[73]							
	2006	2011	2016	2021	2026	2031	2036	2041
Peel Region	14%	12%	9%	8%	5%	5%	5%	5%
City of Hamilton	7%	7%	8%	9%	5%	6%	7%	8%
York Region	20%	17%	13%	12%	7%	7%	7%	7%
City of Guelph	8%	1%	10%	8%	5%	6%	3%	4%
Simcoe County	17%	8%	9%	6%	4%	3%	7%	7%
City of St. Catharines	5%	-9%	4%	5%	3%	5%	5%	7%

[72] The numbers encompass all municipalities in each respective region (York, Simcoe County, Peel)
[73] The numbers encompass all municipalities in each respective region (York, Simcoe County, Peel)

IV Investment Timing and Pacing

4.1 Summary of Expenditures

Table A02 - 13 provides the year-over-year breakdown of customer connection investments, including the historical period from 2015-2018, the bridge year in 2019, and the future period from 2020-2024. Total net costs are presented in this table.

Table A02 - 13: Historical and Proposed Investment Spending

	Historical Expenditure				Bridge	Forecasted Expenditure				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$33.3	$31.8	$26.9	$25.2	$34.7	$31.4	$33.1	$34.8	$36.3	$37.7

Table A02 - 14 breaks this category down further between the types of investments within Customer Connections. All costs are net of contributed capital.

Table A02 - 14: Customer Connection Investment Breakdown

	Historical Spending ($MM)				Bridge	Forecast Spending ($MM)				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Layouts	$2.0	$2.0	$2.0	$2.1	$3.7	$3.9	$4.1	$4.3	$4.5	$4.7
ICI	$10.4	$8.6	$9.8	$7.6	$9.0	$10.3	$10.5	$11.0	$11.5	$12.0
Subdivisions	$19.6	$16.0	$13.2	$13.7	$14.5	$14.9	$16.0	$16.9	$17.5	$18.1
RGEN	$1.8	$0.5	$0.9	-$0.6	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Customer Initiated	-$0.5	$4.7	$1.0	$2.4	$7.5	$2.3	$2.5	$2.6	$2.8	$2.9
TOTAL	$33.3	$31.8	$26.9	$25.2	$34.7	$31.4	$33.1	$34.8	$36.3	$37.7

4.2 Historical Expenditures (2015-2019)

Greenfield Development sustained new connections from 2015 to 2017. In 2018, Brampton, realized a decrease in connections of 56% in 2018 from 2017. Market conditions, mortgage stress test, affordability and increased interest rates contributed to a reduction in development in Brampton. Actual connections continued to slightly exceed planned connections within the two major developing areas of (Markham/Vaughan from 2015 to 2019. Greenfield Development was strong during the 2015 to 2017 period.

Harsh winter conditions in 2015 delayed projects, including the building of new roads. The installation of new electrical infrastructure is typically installed after the new roads are constructed.

In comparison, in 2016 Alectra Utilities realized an increase in cost, as construction projects delayed in 2015 carried over into 2016.

Development was also strong in Mississauga and 2015 and 2016 saw increased number of Industrial/Commercial subdivisions development such as Sheridan College Mississauga Campus, Square One South Expansion, Square One Park, Heartland Business Community Development and Summit City Centre.

The last quarter of 2018 exhibited a small upswing as new home buyers become familiar with the mortgage stress test and market conditions.

Although an increase in service connections occurred, actual construction of projects was slower than anticipated.

Historical expenditures from 2015 to 2019 also included the cost related to renewable as prescribed by the DSC.

4.3 Future Expenditures (2020-2024)

Table A02 - 11 and Table A02 - 12 indicate continued population and employment growth. Alectra Utilities and the Cities/Regions are expecting large growth in the first three years of the DSP horizon and the growth tapers off to a consistent growth rate.

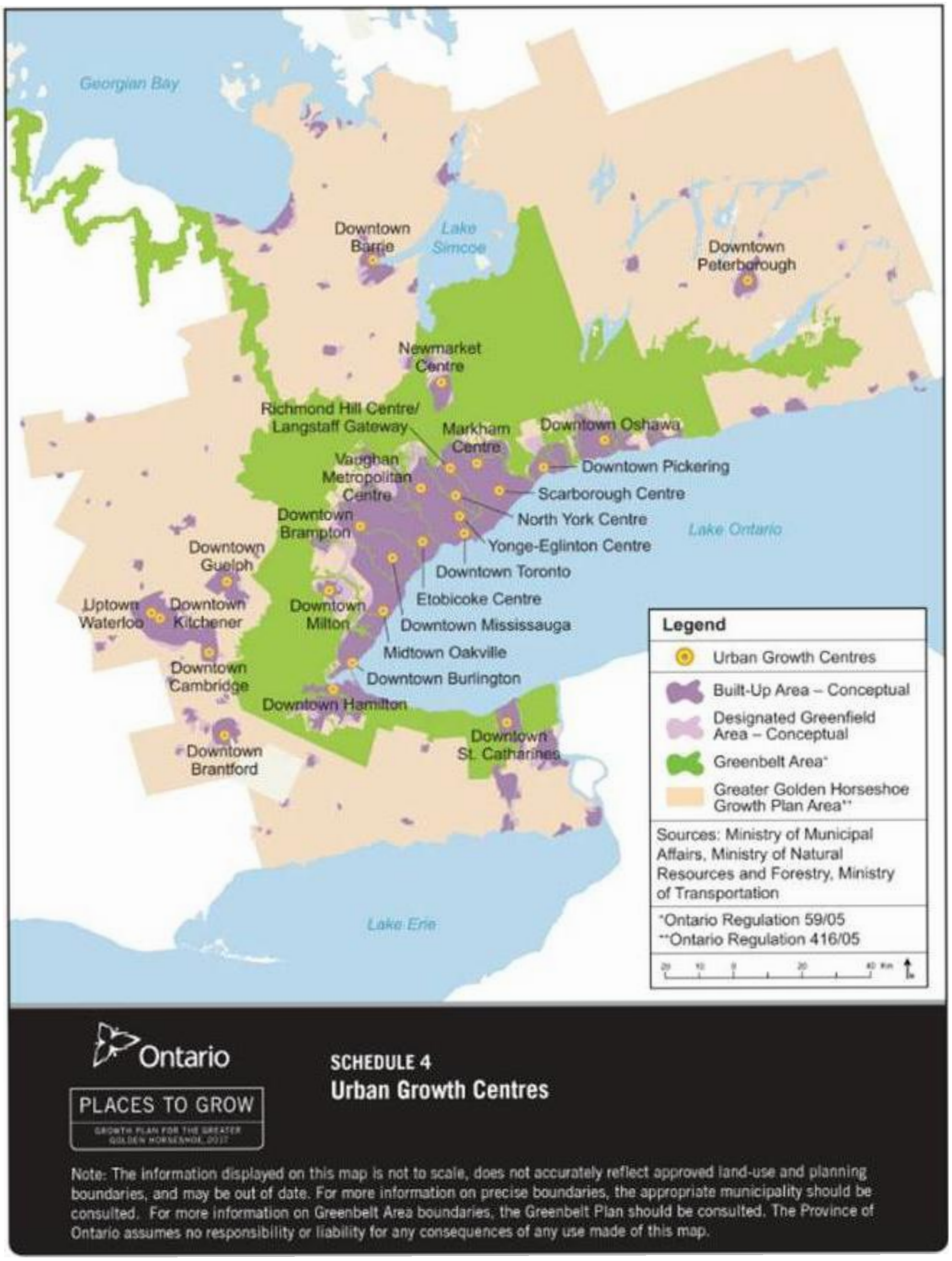
Based on available capacity for connection of renewable generation and awareness of projects under development and historic trends within Alectra Utilities' service territory, Alectra Utilities does not project any capital expenses for the period of 2020-2024 to accommodate the additional connection of renewable generation.

The Greater Golden Horseshoe ("GGH") is one of the fastest growing regions in North America. By 2041, this area is forecast to grow to 13.5 million people and 6.3 million jobs. The GGH Growth Plan 2017 was established to manage future growth within this region. Alectra Utilities' service territories are targeted for continued growth by 2041, namely the City of Hamilton, Mississauga, Brampton and Barrie. Within the Cities "Urban Growth Centres" are being planned and built in coordination with the major transit (Metrolinx) projects which are planned within the various regions. The growth centers are intended to be a catalyst for Development and intensification within the downtown city cores. The Hamilton LRT and Hurontario LRT are two projects being constructed with Alectra Utilities' territory. Similar transit projects completed and or currently under construction in Vaughan have resulted in the Development of VMC and the new subway extension. Mississauga is currently reviewing plans for M-City condo development. Refer to Figure A02 - 13. Future Urban Growth Centres are planned in Markham, Maple and Brampton. Refer to Figure A02 - 14.

In order to limit the consumption of land, Greenfield developments will realize higher intensification, amounting to additional units being installed within Alectra Utilities' service territories.

Figure A02 - 13: Mississauga M-City

Figure A02 - 14: Provincial Growth Plans within Alectra Utilities Service Territory



4.4 Investment Pacing and Prioritization

The pacing of customer connections work is largely determined by factors outside of Alectra Utilities' control. Alectra Utilities works with customers at all levels to optimize the workplan and minimize costs, while maintaining its legal and regulatory requirements.

Scheduling of projects is finalized once the Developer provides the necessary securities, signed agreements, approved drawings and has received the necessary approvals from the City Planning department.

The following factors were utilized when preparing expenditures for future year budgets:

- Historical data;
- Continual communications with development community;
- Number of subdivision applications reviewed for municipalities;
- Regional reports on future residential growth prepared for in the context of Provincial policy and direction;
- Municipal reports on growth management and residential intensification assessment*;
- Reports on housing market;
- Interest and mortgage rates; and
- Government incentives or conditions

Historical service connections are reviewed and are applied as the initial basis to determine forecast connections. Alectra Utilities continually collaborates with the Developer community in discussing future plans within the various territories. City Draft plan submissions are circulated to Alectra Utilities, allowing the opportunity to review and provide comments in regards to future developments at the preliminary stage. Municipal growth forecasts and economic development plans are also referenced to better understand potential developments.

Market conditions, such as interest rates, housing costs, and government policies (stress test) are also referenced to assist in forecasting future conditions.

Subdivision developments are scheduled for construction once all the necessary requirements, as outlined in the Offer to Connect, are provided by the Developer to Alectra Utilities. Once received, Alectra Utilities coordinates with the Developer for timing requirements outlined within both the OTC and the DSC.

4.5 Execution Approach

Customer connections are projects that are dependent on developers providing pre-service requirements (i.e., project design deposits, Letter of Credit deposits, approved engineering drawings and a signed Offer to Connect) for all types of work (layouts, subdivisions, customer initiated projects, ICIs) Once Alectra Utilities received the information that is related to the type of work, designs are completed and scheduled to accommodate Developers/Customers proposed dates to ensure that the site/facility can be energized prior to its occupancy date.

The start date for projects may be contingent on municipal draft plan approvals, site plan approvals, variances or other specific regional or municipal requirements. Developers/ Customers must provide the necessary project deposits. During project pre-construction meetings, Alectra Utilities discusses all the relevant requirements with the developers and finalizes project timelines. Alectra Utilities allocates crews to accommodate energization dates for new service connections and DSC obligations are met.

Projects will be rescheduled due to unforeseen site conditions or delays in the municipal permitting process.

Alectra Utilities' designs are reviewed to ensure projects are issued to Alectra Utilities quality and standards. Alectra Utilities tries to minimize on-site revisions in order to avoid incremental costs. Alectra Utilities has established a process by which firm pricing is received from an approved civil contractor to install the required infrastructure within the development, to Alectra Utilities' standards and specifications. The approved civil contractor was selected through a rigorous tendering process resulting in competitive pricing providing best value. Firm pricing is used when preparing Alectra Utilities' OTC to the Developers.

Winter weather can be a major constraint to connections work in new subdivision. Alectra Utilities applies "frost charges" to projects completed during winter months to recover the increased costs associated with this work. Winter construction is typically initiated by developers, who are made aware of the cost impacts of seasonal work.

V Options Analysis

As all of the work in the Customer Connections portfolio is mandated by legal and regulatory requirements, Alectra Utilities has no option other than to do the work as requested, within the required timelines.

VI Investment Projects

The material investments from 2020 to 2024 that form the Customer Connections investments are included in Table A02 - 15.

Table A02 - 15: Material Projects and Initiatives

Project Code	Project Name	CAPEX ($MM)
101887	New Residential Subdivision Development	$83.7
150449	Services (New and Upgrades) - Commercial, Industrial and Institutional (ICI) Projects	$55.2
101871	Layouts	$21.4
150665	Customer Initiated Distribution System Projects	$13.1

Appendix A03 - Road Authority and Transit Projects

Alectra Utilities' investments in Road Authority and Transit Projects are comprised of two separate portfolios:

a) **Road Authority** projects – projects that are governed under the *Public Service Works on Highways Act* (PSWHA)[74] and are a result of projects by others that require Alectra Utilities to perform work on the distribution system within the public right-of-way; and

b) **Transit** projects – projects driven by the requirements of provincially governed rail transit agencies and as a result require Alectra Utilities to perform work on the distribution system.

These two portfolios are presented separately in this investment summary due to the different nature of cost sharing arrangements.[75]

As set out in the Application Summary (Exhibit 2, Tab 1, Schedule 4), Alectra Utilities has proposed to create an Externally Driven Capital Variance Account ("EDCVA") which would capture the difference between the revenue requirement in rates associated with externally-driven capital expenditures related to Road Authority projects and Transit projects. The EDCVA would mitigate the inherent uncertainty of third-party requirements. Alectra Utilities is proposing to use a forecasted amount for the base of the investments, and use a variance account to track under and over spends over the five-year DSP horizon. At the conclusion of the five years, any under collection will be sought, and any over collection will use an appropriate mechanism to rebate ratepayers.

[74] R.S.O. 1990, c. P.49.

[75] Road Authority projects involve distribution system modifications as a result of road authority requests governed by the PSWHA. Transit projects are rail-related initiatives that require Alectra Utilities to modify the distribution system and are expected to be funded by the Provincial transit agencies.

Part A: Road Authority Related Projects

I Overview

The Road Authority investment portfolio consists of capital work that Alectra Utilities must conduct in order to comply with the PSWHA.

Much of Alectra Utilities' distribution infrastructure is installed along road allowances either above or below public roads (which are called "highways" under provincial legislation). Various municipal, regional and provincial bodies are responsible for managing these roads. These bodies are called Road Authorities. When a Road Authority does work on a road, it may require a utility to relocate or reconstruct its equipment. Under the PSWHA, utilities must comply with the requirements of the Road Authority. Accordingly, the expenditures in this portfolio are non-discretionary.

Depending on the nature of the Road Authority's work, Alectra Utilities' Road Authority investments typically fall into two categories:

- **Relocations**: Moving an existing pole line or duct structure from one location on the road allowance to another location on the road allowance – either on the same side of the road or to the other side; and
- **Reconstruction**: Replacing one form of distribution equipment with another (typically, replacing an overhead pole line with an underground duct system).

Municipalities, the Ministry of Transportation of Ontario ("MTO") and regional authorities establish their road works program for each year, however their work programs often change on short notice, making it extremely difficult for Alectra Utilities to forecast its capital spending for projects that are captured by this initiative. As described on page 1 of this summary, Alectra Utilities has proposed the EDCVA to address the inherent uncertainty in such projects.

Road Authority investments are entirely driven by the requests from the third parties and, as such, the timing when the project starts and is completed depends on the Road Authority. Alectra Utilities participates during the preliminary stages of project planning with the Road Authority, city planners and civil consultants. This ensures that Alectra Utilities can provide comments and recommendations with respect to the distribution system prior to final designs being implemented.

The result is the most efficient and cost-effective designs. Alectra Utilities holds regular planning discussions with the various Road Authorities and also actively participates in various municipal meetings in order to better identify the scope and number of future Road Authority projects.

The Road Authorities in Alectra Utilities' service territory include:

- Region of York
- Region of Peel
- Niagara Region
- Guelph Region
- Simcoe County
- MTO
- The 17 individual municipalities with Alectra Utilities' service territory

Costs associated with the projects are dependent on the size, type and complexity of the individual projects, and divided between the parties as specified in the PSWHA. The allocation of costs is discussed further in section 2.

Table A03 - 1: Road Authority Investment Summary

	Historical Expenditure				Bridge	Forecasted Expenditure				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$9.6	$14.4	$23.5	$31.0	$27.9	$19.7	$17.3	$18.2	$19.2	$20.3
Primary Driver:	Mandated Service Obligations									
Outcomes:	Customer Value, Reliability, Safety, Efficiency, Coordination and Interoperability, Public Policy									

II Investment Description

The specific work involved in any Road Authority project can vary significantly depending on the assets impacted and the nature of the Road Authority request and many other factors (e.g., scope of road widening, traffic and population density, boulevard size, number of utilities involved and availability of space to relocate).

In order to forecast expenditures, Alectra Utilities uses a combination of historic trends and known costs for specific projects. Where the details for planned relocations are available, Alectra Utilities is able to determine the approximate costs associated with the relocations and whether a simple relocation of the existing infrastructure is possible or if the infrastructure has to be reconstructed causing the costs to be higher. For simple overhead to overhead relocations, the costs are calculated based on the initial designs and are directly proportional to the volume of poles, number of dips and taps, and the number of circuits on the poles that are to be relocated.

It is not possible to take a simple approach for all Road Authority projects. For example, the simple approach would not be available where the existing boulevard is already utilized and a relocation further away from the traveled portion of the road is not possible due to aerial encroachment, proximity to the road or proximity to the existing buildings. In such cases, the only option is to reconstruct the existing pole line to underground resulting in substantial increases in the cost associated with the Road Authority project.

Allocation of Costs

The cost sharing for relocating public utilities within a municipal road allowance is determined in accordance with the PSWHA. The PSWHA specifies that a road authority and an electricity distribution company may agree upon the apportionment of the cost of labour. In the absence of an agreement, such costs shall be apportioned equally and all other costs of the work shall be borne by the electricity distribution company. Under the PSWHA, the “cost of labour” is a defined term that includes wages paid to workers as well as other elements, such as the cost of using mechanical labour-saving equipment in the work

For Road Authority relocation requests, Alectra Utilities follows the PSWHA and associated regulations and collects contributed capital of 50% of the labour and labour-saving devices for Road Authority driven projects. As a result, in the absence of an agreement, the costs of a typical road widening project would be allocated 30-40% to the road authority and 60-70% to Alectra Utilities. Various factors may affect the final cost of a project, including unforeseen construction activities, such as the removal of abandoned infrastructure that was not identified during the Subsurface Utility Engineering (SUE) investigations, frost charges, delays caused by other contractors working for the Road Authority.

As permitted under the PSWHA, Alectra Utilities and the Road Authority may agree on different apportionment of the cost responsibility for different portions of the relocation project based on the incremental costs of certain requests made by the Road Authority. At the request of the Road Authority, Alectra Utilities may be required for specific portions of the road widening project to relocate some sections underground, install concrete poles with specifications beyond existing standards and relocate assets at different spacing requirements. Alectra Utilities and the Road Authority may agree to reflect these incremental relocation costs by having the Road Authority bear greater portions of those costs.

The most efficient way to relocate assets is initially established by Alectra Utilities. If the Road Authority wants to upgrade from the proposed solution to a more expensive approach, they are required to pay for 100% of the difference in cost between Alectra Utilities' initial solution and the Road Authority preferred approach.

2.1 Summary of Investment Outcomes and Benefits

Table A03 - 2 summarizes the outcomes and benefits associated with the Road Authority investment.

Table A03 - 2: Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Customer Value	• Allows for new equipment to be installed to better serve customers.
Reliability	• Maintains reliability as aging assets approaching or at end-of-life criteria are replaced with current standard assets. • System expansion investments may involve the addition of new sub-loops and reconfiguration, thus enhancing system performance.
Safety	• Reduces safety risks associated with legacy assets are replaced with new standardized equipment.
Co-ordination / interoperability	• New standards and installation practices allow for safer and easier operations thereby creating better functionality and improved operation requirements.
Public Policy	• Ensures Alectra Utilities' compliance with the PSWHA, the DSC and agreements with the third parties.
Efficiency	• In cases where the scope of the Road Authority investment is extended, the work will be designed and constructed at the same time as the original relocation/expansion, thus saving money in mobilization, switching, restoration and overall project management. • All road authority projects are coordinated to ensure that work is conducted efficiently and to maximize cost-effectiveness.

III Investment Drivers and Need

3.1 Purpose

As described above, the primary driver of this investment is compliance with legislation that requires Alectra Utilities to relocate or reconstruct distribution equipment within the road allowance.

Table A03 - 3 summarizes the primary and secondary drivers of the program.

Table A03 - 3: Investment Drivers

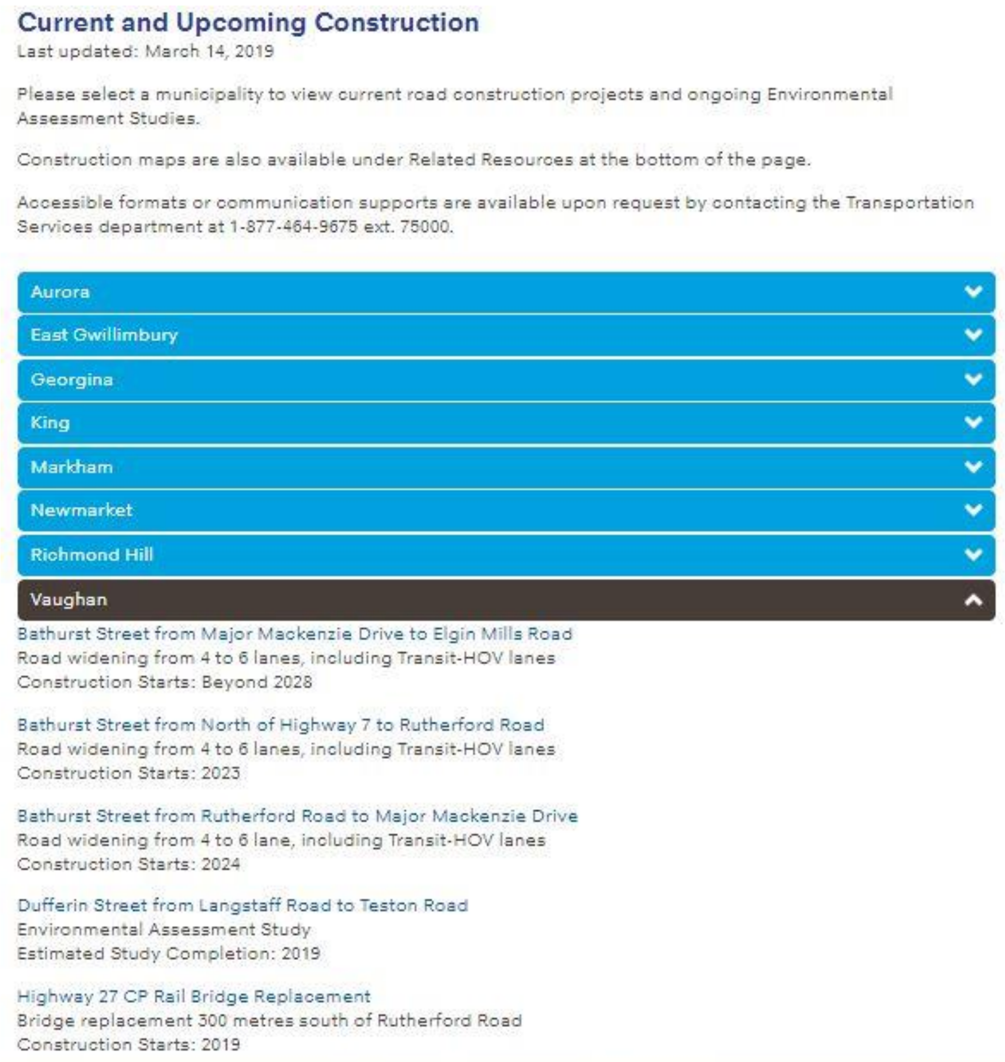
Investment Driver	Reasoning and Investment Benefits
Primary Driver: Mandated Service Obligations	• Compliance with the PSWHA requires all utilities with equipment on or under the highway to cooperate with the Road Authority and relocate the infrastructure as required to allow for future road construction work.

IV Investment Timing and Pacing

4.1 Summary of Expenditures

All of the Road Authority investments are non-discretionary and are required to be initiated and completed in accordance with the direction from the Road Authorities. Many municipalities, the MTO and regional authorities establish road works programs spanning up to ten years. Figure A03 - 1 depicts an example of an updated project list that the Region of York has available. Figure A03 – 2 displays an example of a project in Alectra Utilities' Road Authority mapping repository.

Figure A03 - 1: Region of York Proposed Road Works Schedule



Current and Upcoming Construction

Last updated: March 14, 2019

Please select a municipality to view current road construction projects and ongoing Environmental Assessment Studies.

Construction maps are also available under Related Resources at the bottom of the page.

Accessible formats or communication supports are available upon request by contacting the Transportation Services department at 1-877-464-9675 ext. 75000.

Aurora

East Gwillimbury

Georgina

King

Markham

Newmarket

Richmond Hill

Vaughan

Bathurst Street from Major Mackenzie Drive to Elgin Mills Road
Road widening from 4 to 6 lanes, including Transit-HOV lanes
Construction Starts: Beyond 2028

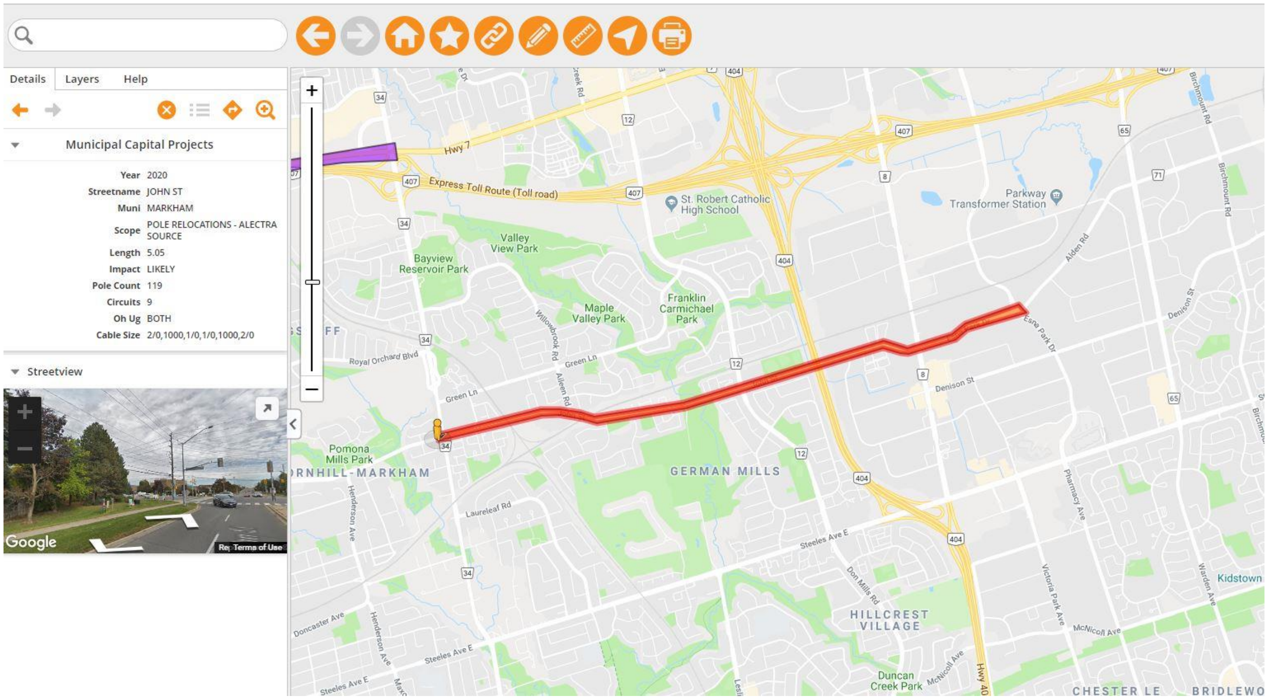
Bathurst Street from North of Highway 7 to Rutherford Road
Road widening from 4 to 6 lanes, including Transit-HOV lanes
Construction Starts: 2023

Bathurst Street from Rutherford Road to Major Mackenzie Drive
Road widening from 4 to 6 lane, including Transit-HOV lanes
Construction Starts: 2024

Dufferin Street from Langstaff Road to Teston Road
Environmental Assessment Study
Estimated Study Completion: 2019

Highway 27 CP Rail Bridge Replacement
Bridge replacement 300 metres south of Rutherford Road
Construction Starts: 2019

Figure A03 - 2: Project in Road Authority Mapping Repository



Despite the existence of long-term plans, the specific projects being conducted each year are subject to change by the Road Authority, making it challenging to accurately forecast the associated capital expenditures. Alectra Utilities constantly attempts to better anticipate these possible requests through participating in meetings with the Cities and Regions and through reviewing site plans and zoning amendments. The expected impact on Alectra Utilities' plant relocation is also based on new, approved work projects from the municipalities, MTO and the regions.

The total annual spending for these investments over the next 5 years is provided in net dollars. These amounts reflect the forecast of Alectra Utilities' required expenditure net of capital contributions. This forecast is based on a combination of historical trends and known costs for specific projects identified through coordination with Road Authorities and through a review of published road works plans from the Regions, Municipalities and MTO that are within Alectra Utilities' service territory.

Table A03 - 4: Historical and Proposed Investment Spending

	Historical Expenditure				Bridge	Forecasted Expenditure				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$9.6	$14.4	$23.5	$31.0	$27.9	$19.7	$17.3	$18.2	$19.2	$20.3

4.2 Historical Expenditures (2015-2019)

Historical expenditures related to Road Authority investments have varied from year to year, however, in 2017 and 2018, expenditures within Alectra Utilities' East service area have been significantly higher due to York Region Rapid Transit (YRRT) initiative, which has required Alectra Utilities to relocate the distribution infrastructure along a large section of Yonge Street and Highway 7. This spending variance is expected to continue into 2019.

As an average, excluding YRRT projects, Alectra Utilities has an annual investment in Road Authority related projects of $10.8MM.

4.3 Future Expenditures (2020-2024)

The anticipated investments for Road Authority projects are based on historical data, as well as the information provided by the regions, municipalities and the MTO regarding specific planned work. Some regions and Municipalities have more detailed future plans regarding their need for the Road Authority relocations, whereas other regions and municipalities have only limited information for the following year and no details for future years.

In 2019, the budget for Road Authority projects within Alectra Utilities' West service territory is expected to be much higher than 2018 year's budget considering several large projects have been scheduled by the City of Hamilton. This includes road authority work associated with First Road West, Waterdown Road, Mountain Brow Road and Birch Avenue.

In addition, for 2019, the spending within Alectra Utilities' East service territory is expected to be higher than average, due to the requirements from the York Region Rapid Transit Corporation, spending will remain at similar levels to last year. In addition, the spending within the York Region area will remain at high levels due to ongoing efforts on the Highway 427 extension project, Keele Street, Bathurst, Rutherford Road, Glen Shields Avenue bridge and St. John's Side Road. The spending within the Barrie service area will be much higher due to several large projects that will be initiated in Barrie, including Bell Farm Road, Harvie Road, Dunlop Street and Mapleview Drive.

Compared to 2018, the spending in the Alectra Utilities' Centre-North service territory is expected to be much higher due to the large volume of relocations, including Goreway Drive, Williams Parkway, Chinguacousy Road, Mayfield Road, Dixie Road and possibly Mississauga Road respectively.

Alectra Utilities anticipates that several large projects will be required to be completed in the utility's Centre-South service territory, such as the Queen Elizabeth Way widening at the Credit River, the QEW widening at Dixie, Canadian National Railway overpass at Dixie, the Highway 401 widening at Creditview, Mavis Road and several other smaller projects. Therefore, spending within Alectra Utilities' Centre-South is forecasted to be above the historical average.

4.4 Investment Pacing and Prioritization

Road Authority investments are considered to be non-discretionary projects and must be completed according to the timelines stipulated by the Road Authority. Therefore, these projects are considered to be a high priority since Alectra Utilities must be compliant with the PSWHA.

As previously noted, the most efficient way to relocate assets is initially established by Alectra Utilities. If the Road Authority wants to upgrade from the proposed solution to a more expensive approach, they are required to pay for 100% of the difference in cost between Alectra Utilities' initial solution and the Road Authority preferred approach.

Alectra Utilities thoroughly reviews all Road Authority investments and compares all projects against the proposed or future initiatives and projects within the Planned Capital, Industrial, Commercial and Institutional, Transit, Subdivision and Substation portfolios. If Road Authority projects are executed at the same locations as other projects, the Road Authority projects take priority as their completion is driven by the PSWHA. Additionally, any potential cost savings through project coordination are explored.

The pacing and prioritization can be further affected by Road Authority investments that were never previously scheduled and must be designed and constructed within the same year, often impacting spending, budgets and resources. Examples include the 410 crossing at Derry Rd. and the 400 crossing at Anne St.

Changes to scope are another risk associated with third party driven projects. Due to these changes, several iterations of the designs are often produced, thereby increasing the cost of the projects. In addition, since these projects are carried out in the road allowances, unforeseen factors often affect the overall cost of the projects, such as conflicts of the proposed infrastructure with the existing plant that was not installed as per the original design or the removal of abandoned structures that were not identified on the initial drawings from the Road Authority.

In some cases, a third party may require certain conditions or have some specifics that Alectra Utilities must follow. Some examples would involve the replacement of the overhead highway crossing with the same infrastructure at a different offset. In some cases, a road authority driving the relocation may not accept Alectra Utilities proposal because it may need to have another contractor working in proximity to the new crossing. In those instances, Alectra Utilities would construct the required crossing as per the road authority requirements, and bill any additional costs to the party requiring the more expensive solution.

In order to manage and mitigate uncertainties in relation to road authority projects, Alectra Utilities has ongoing discussions with the municipalities as well as other road authorities to make sure it is aware of their plans and adjust its schedule to meet their timelines. Alectra Utilities has retained external contractors working at different work sites throughout the year under a multi-year engineering procurement construction Master Service Agreement. Regular progress meetings are held to ensure technical and operational issues are resolved promptly.

Alectra Utilities intends to create a variance account for Road Authority projects to mitigate the uncertainty of third-party requirements. Alectra Utilities will use the amount stated in the DSP for the base of the investments, and use a variance account to track under and over spends over the 5-year DSP horizon. At the conclusion of the five years, any under collection will be sought, and any over collection will use an appropriate mechanism to rebate ratepayers.

4.5 Execution Approach

Since Road Authority investments are entirely dependent on the Road Authority timelines, Alectra Utilities will schedule the projects as they are requested, once Alectra Utilities ensures it has sufficient resources to carry out the work. As these projects are non-discretionary, Alectra Utilities does not attempt to re-prioritize these projects since they must be completed as soon as the Road

Authority is ready and the necessary construction deposits or Purchase Orders have been provided.

The design for each individual project is started when 60% of the design from the Road Authority consultant is provided to Alectra Utilities. The design is completed and construction is scheduled at least two months ahead, allowing for the crews' mobilization, the completion of locates, and the acquisition of materials.

The project is then released to the crews or, if internal resources are not available, the project is released to Alectra Utilities' approved contractor for construction. Once the job is completed, Alectra Utilities will invoice or return the difference between the initial estimate and actual final costs.

V Options Analysis

Given that Alectra Utilities must meet its statutory obligations in accordance with the PSWHA, this investment is non-discretionary. There is no alternative other than to proceed with the work as requested. As described above, Alectra Utilities takes all available steps to minimize and properly allocate costs between parties to each project, and to make the most efficient use of the available resources.

VI Investment Projects

Since Road Authority projects are non-discretionary and dependant on other parties, the budgets for each year will vary based on the volume of requests and the type of requests by others. In the majority of cases, like for like relocations are possible. However, at times where the lack of real estate or the proximity to buildings or roads prevents Alectra Utilities from achieving a like for like replacement, the system would need to be reconstructed to underground with a large impact to the budget.

Alectra Utilities' relocations are contingent on other work performed by the Road Authorities. Some projects may be delayed, accelerated or added to the list of projects for next year.

The list below shows the known major projects that are anticipated for 2019 in Alectra Utilities' territory:

- First Road West
- Waterdown Road
- Mountain Brow Road
- Birch Avenue
- YRRTC
- Main Street
- Bell Farm Road
- Harvie Road
- Dunlop Street
- Mapleview Drive
- HWY 427 Extension
- Keele Street
- Bathurst Street
- Rutherford Road
- Glen Shields Avenue Bridge
- Goreway Drive
- Williams Parkway
- Chinguacousy Road
- Mayfield Road
- Dixie Road
- Mississauga Road
- QEW widening at Credit River
- QEW widening at Dixie
- CNR overpass at Dixie
- HWY 401 widening at Creditview
- Mavis Road

The material investments from 2020 to 2024 that form the Road Authority investments are included in Table A03 - 5.

Table A03 - 5: Material Projects and Initiatives

Project Code	Project Name	CAPEX ($MM)
150645	Road Authority	$91.3
150343	Bathurst Street Widening	$3.4

Part B: Transit Related Projects

I Overview

Transit initiatives are implemented by federal, provincial, regional, and/or municipal agencies, such as Metrolinx. These projects are related to rail lines - Light Rail Transit or Express Rail transit projects in Alectra Utilities' service territory. Alectra Utilities' participation with these governments during the Pre-Market, In-Market, and in development periods of the projects to ensure existing Alectra Utilities' infrastructure is relocated in a timely manner

Transit projects involving rail lines primarily affect Alectra Utilities' aerial circuits which crossover the rail tracks and require the relocation of Alectra's infrastructure to resolve conflicts. Investments in this portfolio are non-discretionary.

Like Road Authority work, Alectra Utilities' investments in Transit projects typically fall into two categories:

- **Relocations**: Moving an existing pole line or duct structure from one location in proximity to the rail lines to another location – either on the same side of the tracks or to the other side
- **Reconstruction**: Replacing one form of distribution equipment with another (typically, replacing an overhead pole line with an underground duct system)

Currently forecast Transit projects include:

- Hurontario Light Rail Transit (HuLRT) – Metrolinx and Infrastructure Ontario;
- Hamilton Light Rail Transit (HaLRT) – Metrolinx and Infrastructure Ontario; and
- Regional Express Rail (RER) – Metrolinx and Infrastructure Ontario.

The HuLRT project scope includes the relocation of Alectra Utilities' infrastructure along the 20.9 km LRT route in Mississauga and Brampton and is expected to be completed over the next six years with a total gross cost of $65.1M within this financial plan timeframe. The project is expected to require expenditures of $9.75M by Alectra Utilities, all of which is expected to be recoverable from Metrolinx, with the remainder to be paid directly to the "Project Co" by Metrolinx.

The HaLRT project scope includes the relocation of Alectra Utilities' infrastructure along the 14 km LRT route in Hamilton and is expected to be completed over the next seven years with a total gross cost of $79.7M within this financial plan timeframe. The project is expected to require expenditures of $12.5M by Alectra Utilities, all of which is expected to be recoverable from Metrolinx.

The RER project has a scope of relocating approximately 89 overhead conflicts along the Barrie, Stouffville, Kitchener and Lakeshore West GO Rail Corridors at a cost of $41.4MM with a requested completion date of 2021. All costs are expected to be recoverable from Metrolinx.

Table A03 - 6: Transit Investment Summary

	Historical Expenditure				Bridge	Forecasted Expenditure				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Primary Driver:	Third-Party Requests									
Secondary Drivers:	Mandated Service Obligations, Customer Service Requests									
Outcomes:	Customer Value, Reliability, Safety, Efficiency									

II Investment Description

Transit Projects represent large scale relocation projects that are required by federal, provincial, regional, and/or municipal agencies in order to support the installation of New Rapid Transit Infrastructure.

Specific activities taking place within the investment include the relocation of Alectra Utilities' infrastructure to support New Rapid Transit Infrastructure, third-party plant relocation in order to support these initiatives.

Key benefits include that mandated service and customer service obligations are met. Other benefits include the fact that assets approaching or at end-of-life criteria will be replaced as part of this investment. Assets within hard-to-access locations will also be relocated to safer and more accessible locations. Reliability will be improved through the deployment of the newest asset standards and technologies. Cost efficiencies are also captured as assets are replaced through provincial funding, as opposed to funding directly by the utility.

Ultimately, Alectra Utilities' work supports the installation of clean efficient rapid transit infrastructure as part of efforts to reduce the need for automobiles and further prevent gridlock.

2.1 Summary of Investment Outcomes and Benefits

Table A03 - 7 summarizes the outcomes and benefits associated with the Transit Projects investment.

Table A03 - 7: Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Customer Value	• As these investments support the development of transit systems, customers who utilize these systems will experience the direct benefits. • Customers gain indirect value from these efforts
Reliability	• Increase reliability for the corridor by removing older assets that are closer to their end of life. Adding and improving switching will be completed.
Safety	• Replacement of assets with newer should decrease the potential of failure offsetting any possible public safety concerns. Relocation of assets off transit corridors ensures access to manholes/switchgears/transformers are from side streets allowing for better traffic control, slower traffic and less pedestrians.
Efficiency	• Productivity improvements and efficiency will be gained as part of this investment. For example, the replacement of manual switches with new SCADA-enabled switches that are compatible with a Distribution Automation approach will introduce productivity improvements as field crew workers no longer need to go to the field to manually operate switches.

III Investment Drivers and Need

3.1 Purpose

When transit authorities execute new projects that require the construction of new infrastructure, this often results in a need for the local utilities to relocate their existing asset infrastructure. This presents an opportunity for Alectra Utilities as the transit authority is required to pay for the relocation of the Alectra Utilities' distribution system since transit projects are not regulated under the PSWHA. Rather than simply relocate existing assets, the opportunity exists to replace equipment with new equipment installed in the new location.

This work is essential to allow the transit authority to deliver their projects on time to the customers they serve. Alectra Utilities' Transit projects will provide support to all applicable transit authorities within its jurisdiction.

As such, the primary driver of this work is third-party requests, while secondary drivers include mandated service obligations and customer service requests.

Table A03 - 8: Investment Drivers

Investment Driver	Reasoning and Investment Benefits
Primary Driver: Third-Party Requests	These investments are being executed as a direct result of the third-party who is requesting for the associated relocations. The third party will pay all costs associated with the investments.
Secondary Driver: Customer Service Requests	Metrolinx (i.e., the customer) will require new connections for the newly installed transit infrastructure, and so therefore customer service requests remain a secondary driver.
Secondary Driver: Mandated Service Obligations	This work must be executed as a requirement for the utility to connect with the new customers, as defined in the Distribution System Code (DSC) and therefore this work represents a mandated service obligation.

IV Investment Timing and Pacing

4.1 Summary of Expenditures

Table A03 - 9 provides the year-over-year breakdown of transit project investments, including the historical period from 2015-2018, the bridge year of 2019, and the future period from 2020-2024.

As a provincial transit agency implementing rail transit projects in Alectra Utilities service area, Metrolinx is not recognized by Alectra Utilities as road authority under the definition of the PSWHA. Since cost sharing provisions as set out in the PSWHA are not applicable to transit projects implemented by Metrolinx, Alectra Utilities is working to finalize arrangements with Metrolinx to bear all the relocation costs associated with the three identified transit projects. Due to the lack of final designs and project specifics, certain sections of the distribution system required to be relocated may require a different cost sharing arrangement with Metrolinx. For example, in certain rail crossing locations it may be more economic and safe for Alectra Utilities to relocate the distribution from an overhead to an underground crossing. As the final designs, including the specific numbers of crossings to be remediated, have not been finalized by Metrolinx, the costs for distribution relocation work in connection with these projects have not been developed. Alectra Utilities continues to monitor the progress and timelines of the project schedules, which are controlled by Metrolinx. As a result, Alectra Utilities has not incorporated any capital expenditure costs over the forecasted planning period.

Table A03 - 9: Historical and Proposed Investment Spending

	Historical Expenditure				Bridge	Forecasted Expenditure				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0

4.2 Historical Expenditures (2014-2018)

Transit projects are a new type of project that did not exist as a distinct category prior to 2018.

4.3 Future Expenditures (2019-2024)

All costs associated with this portfolio will be covered by Metrolinx. Included in these costs is the RER project scope which includes the relocation of 89 overhead assets along the Barrie, Stouffville, Kitchener and Lakeshore West GO Rail Corridors. Total costs will be $41.4MM with a completion date of 2020.

Alectra Utilities has performed some preliminary engineering designs and is in discussions with Metrolinx with respect to thirteen crossings where like for like relocation does not provide adequate safety and operational requirements. Final locations, type of construction and funding allocations are not yet determined. Any investments that are required by Alectra Utilities are proposed to be placed in a variance account within the Transit related projects. The high-level estimate is $9.3MM.

Also included is the HaLRT scope, including the relocation of infrastructure along the 14km LRT route in Hamilton. This work is expected to be performed over a 7-year period with a total gross cost of $79.7MM in spending which will be entirely recoverable from Metrolinx.

As part of the HaLRT project in Hamilton, some early-works projects were identified where utility infrastructure needed to be modified to accommodate the LRT. This project identifies a new 13.8kV feeder required from Lake TS to supply a Metrolinx Track Powered Substation Station (TPSS#8) along the LRT corridor, as the existing 13.8kV feeder in the area is unable to accommodate the additional load. The new feeder will also have load transferred to it from the existing 13.8kV feeders in the area, to alleviate the capacity constraints in the vicinity.

Finally, the HuLRT project scope is the relocation of infrastructure along the 20.9km LRT route in Mississauga and Brampton and is expected to be completed over the next six years with a total gross cost of $65.1MM within this DSP term. Only $9.75MM will be spent by Alectra Utilities, all of which is recoverable from Metrolinx; the remainder will be paid directly to the "Project Co" by Metrolinx.

4.4 Investment Pacing and Prioritization

The pacing, prioritization and overall timing for the relocation projects will be entirely dependent on Metrolinx, and will not be known until a schedule is provided from the company (Project Co.) who will be working with Metrolinx to deliver the HuLRT and HaLRT projects respectively.

4.5 Execution Approach

All relocation activities will be coordinated between Metrolinx and the company who is working with Metrolinx to deliver the transit system upgrades.

V Options Analysis

Transit projects are driven by the requirements of the provincial transit agencies. Alectra Utilities is required to complete modifications on the distribution system to support such transit projects.

VI Investment Projects

There are no material projects and initiatives for Transit Related Projects from 2020 to 2024.

Appendix A04 - Transmitter Related Upgrades

I Overview

The Independent Electricity System Operator's ("IESO") regional planning process has identified several end of life upgrades to transmission system infrastructure owned and operated by Hydro One Networks Inc. ("HONI"). As part of these transmission system upgrades, Alectra Utilities and other distributors are often required to relocate some of their distribution equipment.

HONI's planned transmission system upgrades will require Alectra Utilities to relocate and reconfigure its equipment at two Transformer Stations ("TS") during the DSP period. This work is necessary to integrate Alectra Utilities' distribution infrastructure with the newly installed HONI equipment at these stations. Alectra Utilities' total forecast expenditures for this work are $2.8MM.

Table A04 - 1 provides an overall summary of transmitter related upgrades, drives and outcomes over the next six-year period.

Table A04 - 1: Investment Subgroup Summary

Historical Spending					Bridge	Forecast Spending				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$0.0	$0.0	$0.0	$0.0	$0.5	$0.6	$2.2	$0.0	$0.0	$0.0
Primary Driver:	Mandated Service Obligations									
Secondary Drivers:	Customer Service Requests									
Outcomes:	Reliability, Safety, Environment, Coordination and Interoperability, Efficiency									

II Investment Description

The IESO-led regional planning process[76] identified three projects that will require coordination between Alectra Utilities and HONI during the DSP term from 2020 to 2024:

- Barrie TS upgrades
- Kenilworth TS Upgrades

As part of its obligations within the Distribution System Code ("DSC"), Alectra Utilities is required to work in coordination with HONI to support the necessary upgrades, and in some cases, relocate existing Alectra Utilities plant to support the renewal of the transmission system. The following subsections provide further details on the TS investments required by this investment.

2.1 Barrie TS Upgrade- Feeder Relocation and Metering

Hydro One will be rebuilding and reconfiguring its Barrie TS. As part of this upgrade, Hydro One plans to increase the capacity from 55/92 MVA to 75/125MVA and upgrade the E/4B transmission line from 115KV to 230KV. A hand off letter was issued by IESO to Hydro One on December 2015 to begin development of a project to upgrade the existing Barrie TS and the E3/4B transmission line with a new 230KV infrastructure. Please refer to section 5.2.2.8- A for details on this project.

The new station will be constructed west of the existing station, thereby expanding the fenced area westward. Hydro One will also move the station egress westward and include an additional feeder for InnPower. The feeder egress relocation and additional feeder will require integration reconfiguration for the six Alectra Utilities feeders (13M3 to 13M8) emanating from the station. Alectra will need to relocate the existing feeders, 13M3 to 13M8, to match with the breaker line up of the new.

In addition to the feeder reconfiguration, Alectra Utilities is responsible for upgrading the revenue metering equipment at Barrie TS as per Schedule 4 of the Hydro One Customer Wholesale Revenue Metering Agreement. Alectra Utilities will install six PME's 2 element delta metering and

[76] The dates provided are the initial dates from RIP report. HONI has since revised the execution dates.

associated communication, protection and switching. The cost of this work for Alectra Utilities is forecast to be $2.2MM in 2021.

2.2 Kenilworth TS Upgrades

The regional planning activities in the Hamilton region identified a number of stations that were at the end of life and HONI has proposed sustainment activities for a number of stations. Please refer to Table 5.2.2 - 5[76] and Table 5.2.2 - 6[76] in section 5.2.2 for a list of the sustainment projects in near, mid and long term.

HONI will be replacing transformers at Kenilworth TS which is at physical end-of-life, as well as switchgear. This replacement targeted is for Q1 2020. Alectra Utilities role in the project will be to coordinate planned outages and disconnect and reconnect feeder egress connections. Alectra Utilities will also coordinate with their customers to facilitate any required protection upgrades. The cost of this work for Alectra Utilities is forecast to be $0.6MM in 2020.

2.3 Summary of Investment Benefits

Alectra Utilities work under the Transmitter Related Upgrades portfolio is mandatory, as it is required to enable work at HONI. While the work is not driven by Alectra Utilities, the overall project will provide benefits for Alectra Utilities customers. Table A04 - 2 summarizes the outcomes and benefits associated with the Facilities investment.

Table A04 - 2: Investment Outcomes and Benefits

Investment Benefits	Reasoning and Investment Benefits
Reliability	By addressing those HONI assets that are at end-of-life, any reliability risks towards Alectra Utilities customers can be mitigated accordingly.
Safety	Replacement of end-of-life HONI infrastructure mitigates the chances of a catastrophic failure mode, which can result in substantial safety impacts to both field crew workers as well as the public.
Environment	Replacement of end-of-life HONI infrastructure mitigates the chances of a catastrophic failure mode, which can result in substantial environmental impacts to both field crew workers as well as the public.
Coordination and Interoperability	This investment allows Alectra Utilities to sufficiently coordinate with HONI such that their newly installed and reconfigured substation equipment can sufficiently connect to the Alectra Utilities distribution system.
Efficiency	These investments are expected to further improve operational flexibility across the transmission and distribution systems, such that if there is a loss of supply, HONI will have the capability to resolve the issue in a more optimized manner, therefore also restoring Alectra Utilities customers in a more timely manner.

III Investment Drivers and Need

3.1 Purpose

Under the DSC, Alectra Utilities is required to coordinate with HONI as it conducts asset renewal activities which will be taking place at Barrie TS and Kenilworth TS. This work is necessary to ensure that HONI's equipment is appropriately reconnected and reconfigured to support Alectra Utilities distribution system. Therefore, the primary driver of this investment is Mandated Service Obligations, with the secondary driver being Customer Service Requests.

Table A04 - 3: Investment Drivers

Investment Driver	Reasoning and Investment Benefits
Primary Driver: Mandated Service Obligations	Alectra Utilities is required to coordinate with HONI, as per the DSC, to ensure that newly installed assets can be safely connected and configured to Alectra Utilities distribution system.
Secondary Driver: Customer Service Requests	By coordinating with HONI for their asset renewal activities, Alectra Utilities is ensuring that it meets customer service requests

The following subsections highlight the specific needs and drivers of this investment for each of the three substations.

3.1.1 Barrie TS Upgrades

As part of regional planning work, Hydro One initiated a Needs Screening process for the South Georgian Bay/Muskoka planning region in 2014. The South Georgian Bay/Muskoka Needs Screening study team determined that there was a need for coordinated regional planning, resulting in the initiation of the Scoping Assessment process with the IESO.

The South Georgian Bay/Muskoka Scoping Assessment Outcome Report was filed in June 2015 and identified two sub-regions for coordinated regional planning: Barrie/Innisfil and Parry Sound/Muskoka.

Subsequent to the scoping assessment process the Barrie/Innisfil Integrated Regional Resource Plan ("IRRP") was completed in 2015. A IRRP[77] recommended that the circuit E3/4B should be rebuilt to 230 kV and the Barrie TS upgraded to 75/125 MVA rated transformers. The targeted in service date for the project was at the end of 2020 however per the latest information obtained from HONI the project is now scheduled for completion in 2021.

A hand off letter was issued by IESO to Hydro One on Dec 2015 to begin development of a project to replace the existing Barrie TS and the E3/4B transmission line with a new 230KV infrastructure.

Currently, all seven existing 44 kV feeder positions available at Barrie TS have been allocated to the LDCs. Six of these feeders are used to supply Alectra Utilities customers and one is used to supply customers of another LDC. The updated Barrie TS will have six feeders allocated to supply Alectra and two feeders for the other LDC customers.

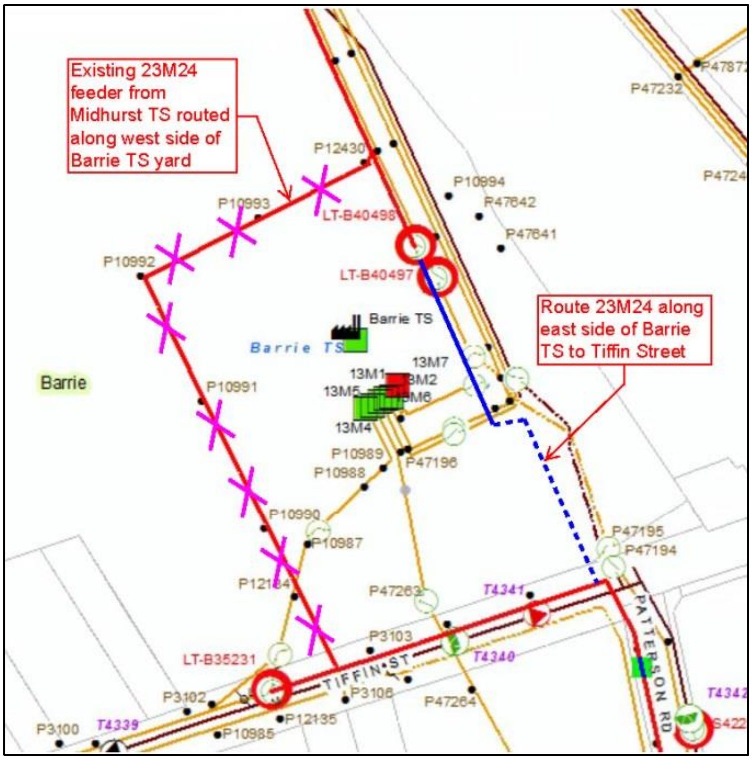
Hydro One will also be moving the station egress westward and adding an additional feeder. As a result the feeder designations will change to 13M1-13M2 for other LDC and 13M3-13M8 for Alectra Utilities.

The feeder integration will have the two circuits supplying other LDC customer going west from the station along Tiffin. Alectra Utilities will need to relocate feeders 13M3-13M8 to match the breaker line up for the upgraded station while avoiding crossing other LDC's circuits 13M1 and 13M2.

In addition, Alectra Utilities will need to relocate the existing Midhurst feeder 23M24 which goes along the west side of Barrie TS to accommodate the westward expansion of the upgraded station. The 23M24 will be relocated to the east side of Barrie TS for integration on Tiffin Street, as per Figure A04 - 1.

[77] The IRRP report is included in Appendix H02 - Barrie / Innisfil Sub-Region IRRP

Figure A04 - 1: 23M24 Routing



In addition to the feeder reconfiguration, Alectra Utilities is responsible for upgrading the revenue metering equipment at Barrie TS as per Schedule 4 of the Hydro One Customer Wholesale Revenue Metering Agreement. Alectra Utilities will install six Primary Metering Elements ("PMEs"), 2 element delta metering, and associated communication, protection, and switching.

3.1.2 Kenilworth TS Upgrades

The purpose of this project is to replace existing end-of-life equipment, including power transformer T3 and E/J metalclad switchgear. This initiative will also involve the reconfiguration of the substation with the removal of transformers T1 and T4 along with the removal of the D/K switchgear. Kenilworth TS serves 2 very large industrial customers with 54.6 MVA of connected load.

As a result of the work being performed by HONI, Alectra Utilities will be required to relocate existing assets to align with the new equipment installed by HONI. This includes cutting and splicing into 11 PILC cables, installing CTM to change the feeder cable over to XLPE as well as installing short runs of XLPE cable so it can be terminated into the new equipment. In addition, Alectra Utilities will be installing new cable chambers, as only a limited number of CTMs can be safely accommodated within the existing chamber. Pursuant to HONI’s requirements, these chambers will have to be installed in the road right-of-way.

IV Investment Timing and Pacing

4.1 Summary of Expenditures

Table A04 - 4 provides the year-over-year breakdown of overhead asset renewal investments, including the historical period from 2015-2018, the bridge year in 2019, and the DSP period from 2020-2024.

Table A04 - 4: Historical and Proposed Investment Spending

	Historical Spending				Bridge	Forecast Spending				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$0.0	$0.0	$0.0	$0.0	$0.5	$0.6	$2.2	$0.0	$0.0	$0.0

4.2 Historical Expenditures (2014-2019)

Historical expenditures between 2015 and 2019 are $0.5MM related to relocations at Elgin TS.

4.3 Future Expenditures (2020-2024)

Forecast expenditures from 2020 to 2024 total $2.8MM. The expenditures were derived based on detailed design and include the work that Alectra Utilities must execute in order to sufficiently integrate its infrastructure with the newly installed HONI equipment.

The 2020 project is related to Kenilworth TS upgrade and 2021 project is related to Barrie TS upgrade.

In addition the IRRP/RIP process has identified several HONI sustainment initiatives during the DSP period which are detailed in Section 5.2.2 and may require Alectra Utilities to initiate work and further investment during the DSP period. These investments have not been included due to the limited information on the timing and scope.

4.4 Investment Pacing and Prioritization

Alectra Utilities will prioritize its activities in tandem with HONI's schedule, such that any delays can be avoided accordingly.

4.5 Execution Approach

Alectra Utilities will leverage internal and external contractors to complete the reconfiguration of assets to be connected to HONI's new infrastructure. Alectra Utilities design and engineering team coordinates with HONI with the design phase followed by coordination with the construction team. Regular progress meetings are held with HONI to ensure technical and operational issues are resolved promptly.

The Execution phase will follow Alectra Utilities' internal project management methodology which provides specific guidelines, procedures, work instructions, and industry best practices that allow the project work to be performed in an economically efficient, cost effective, and safe manner.

V Options Analysis

Alectra Utilities must execute the Kenilworth TS project in co-ordination with HONI, as it is mandated as part of the section 8 of DSC requirements.

Alectra Utilities is also required to execute the planned work at Barrie TS. However, Alectra Utilities does have multiple options with respect to how the new Barrie TS assets can be configured to Alectra Utilities' grid. These options are considered within the following subsections.

Both options for the Barrie TS project include relocating the feeder 23M24 from Midhurst and the six feeders (13M3-13M8) to match the breaker line up for the upgraded Barrie TS. The difference between the two options relates to the metering solution to be installed. As per Schedule 4 of the Hydro One Customer Wholesale Revenue Metering Agreement, Alectra is responsible for upgrading the revenue metering equipment at Barrie TS. The two possible revenue metering options are; (i) station bus metering, or; (ii) utility feeder metering using PME's.

Using station bus metering introduces accessibility issues and is higher-cost. In the past, Alectra Utilities has noted accessibility issues with the existing station bus metering at Barrie TS. The bus metering is a more expensive solution than feeder metering. The total cost for this option utilizing bus metering is $2.6MM. This option has been rejected as this more expensive and Alectra Utilities has noted accessibility issues with the existing bus metering.

Installing utility feeder metering using PMEs will solve the access issues associated with the bus metering, and costs less than the station bus metering option. The total cost for this option is $2.2MM.

VI Investment Projects

The material investments from 2020 to 2024 that form the Transmitter Related Upgrades investments are included in Table A04 - 5.

Table A04 - 5: Material Projects and Initiatives

Project Code	Project Name	CAPEX ($MM)
150259	Barrie TS Upgrade Feeders and Metering	$2.2

Appendix A05 - Overhead Asset Renewal

The investments in Alectra Utilities' Overhead Asset Renewal portfolio are divided into two categories:

a) **Deteriorated Assets and Assets Prone to Adverse Weather** – Replacing and remediating overhead assets that are deteriorated or assets prone to failure in adverse weather conditions.
b) **Voltage Conversion Projects** – Replacing deteriorated lower-voltage distribution equipment.

Deteriorated Assets and Assets Prone to Adverse Weather are discussed in Part A. Voltage Conversion Projects are discussed in Part B.

Part A: Deteriorated Assets and Assets Prone to Adverse Weather

I Overview

Alectra Utilities' planned Overhead Asset Renewal investments will replace and remediate deteriorated overhead assets and assets prone to failure in adverse weather conditions. This work is driven by public and worker safety, and by the reliability needs of the distribution system.

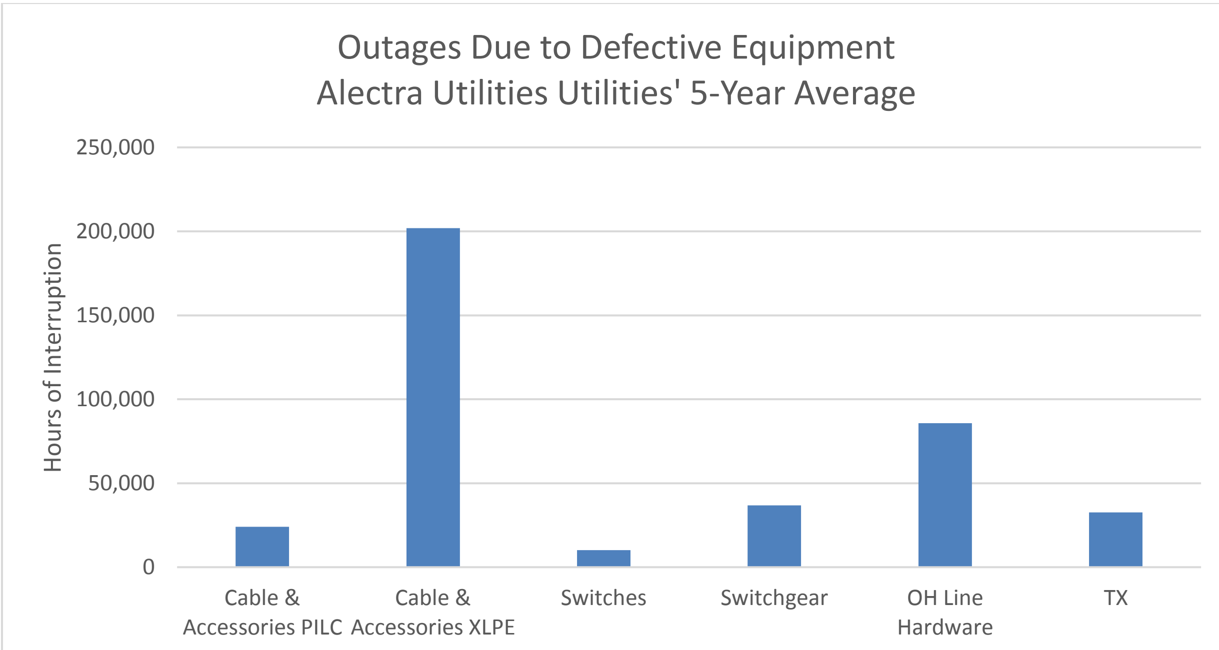
Figure A05 - 1: Downed Overhead Line on Warden Avenue in Markham in 2018

If not addressed, deteriorated overhead equipment would pose an unacceptable safety risk to the public, utility workers and contractor crews who work in proximity to these assets. A single pole failure is a serious safety risk. However, when multiple poles fail – due to their condition or to the adverse weather events, which are becoming increasingly frequent – the failure can cascade down a street, bringing down multiple poles, as shown in Figure A05 - 1. These catastrophic failures of the overhead system are a very serious safety risk.

Deteriorated overhead infrastructure also negatively affects customers' reliability. As shown in Figure A05 - 2, failing overhead distribution hardware is the second largest contributor to equipment related failures. This fact reflects both a large amount of overhead equipment in Alectra

Utilities' distribution system, and the condition of those assets. The planned expenditures are necessary to maintain reliability near current levels.

Figure A05 - 2: Outages Due to Defective Equipment, Alectra Utilities' 5-Year Average (2014-2018)



Through the investments described in this section, Alectra Utilities will replace deteriorated assets and obsolete infrastructure with infrastructure constructed to present day standards. Key overhead assets to be remediated and replaced over the 2020 to 2024 DSP period include:

- **Poles:** Alectra Utilities' plan includes two groups of investments in distribution poles: Pole Renewal for deteriorated poles, and Storm Hardening for select poles. Pole Renewal investments will remediate deteriorated wood and concrete poles that are in Poor or Very Poor condition. However, where it is practical and cost-effective, Alectra Utilities will reinforce deteriorated poles in-lieu of replacement. Through the Storm Hardening investment, Alectra Utilities will replace specific segments of wood poles that are prone to catastrophic failures under adverse weather conditions.
- **Overhead Switches:** Alectra Utilities has investments plan to address deteriorated overhead switches identified to be in Poor and Very Poor condition.
- **Insulators Prone to Failure:** Alectra Utilities plans to replace certain insulators that have shown a high risk of failure, leading to flashover outage events and pole fires. Specifically,

the planned investments will replace legacy porcelain insulators and first-generation polymeric insulators that are prone to cracking, which has led to powerlines falling to the ground and introducing a significant public safety risk.

Through the work planned in the Overhead Asset Renewal investment portfolio, Alectra Utilities will mitigate and where possible, avoid the failure risk associated with deteriorated overhead infrastructure.[78] Alectra Utilities also plans to replace specific failure prone and obsolete infrastructures such as porcelain insulators, first-generation polymeric insulators, and air-brake switches. These failure-prone and obsolete assets create safety and reliability risks; which Alectra Utilities will mitigate through the planned investments.

Table A05 - 1 summarizes the investments planned in the Overhead Asset Renewal portfolio during the term of the DSP 2020-2024, actual historical expenditure in the period 2015-2018, and 2019 as the bridge year.

Table A05 - 1: Overhead Asset Renewal Investment Summary

	Historical Spending				Bridge	Forecast Spending				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$20.7	$25.0	$23.0	$21.7	$26.1	$23.2	$24.8	$26.0	$26.5	$27.0
Primary Driver:	Failure Risk									
Secondary Drivers:	Reliability, Functional Obsolescence, Resilience to Adverse Weather, Safety									
Outcomes:	Reliability, Safety, Customer Value, Reliability, Efficiency									

Alectra Utilities has several initiatives that target poles, two of which are included in this portfolio (Pole Renewal and Storm Hardening). Other investments that include pole remediation include road widening, voltage conversions, and rear-lot replacement initiatives.

The remainder of this evidence is organized around the four planned categories of investment:

- Pole Renewal (Section II),
- Storm Hardening (Section III),

78 Overhead assets targeted for renewal either have Health Index results of Very Poor or Poor, as identified by the Asset Condition Assessment (ACA) process, or belong to specific asset groups that have been identified as being functionally obsolete or at high risk of failure. For additional details on Alectra Utilities asset condition assessment processes, please refer to Section 5.3.3 as well as Appendix D - Asset Condition Assessment – 2018

- Switches (Section IV), and
- Insulators Prone to Failure (Section V).

For each category, Alectra Utilities describes the proposed investments, the drivers and need for the work, the proposed timing and pacing, and the alternatives considered by the utility.

Table A05 - 2 summarizes the outcomes and benefits of the investments planned to address deteriorated poles.

Table A05 - 2: Summary of Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Customer Value	• Customers will experience improved safety. Remediating deteriorated poles and planned Storm Hardening investments will mitigate potential catastrophic failures of the overhead system in storm events. • Customers will experience improved reliability as a result of the remediating deteriorated poles. In addition, Storm Hardening will improve the system resilience in storm events mitigating prolonged outages.
Reliability	• Remediating deteriorated poles will help maintain system and feeder-level reliability. • Replacing non-functional switches with operational switching points will enhance outage restoration procedures, thereby further minimizing customer impacts during an outage. • Replacing deteriorated and functionally obsolete assets with assets constructed to present day standards will enhance reliability. • Storm Hardening investments will improve the overhead system resilience to storms by minimizing the impact of storm damage onto the system.
Safety	• Alectra Utilities plans to realize safety improvements through the construction of new, standardized equipment that aligns to current operational practices. For instance, the risks of catastrophic failure associated with degrading poles (i.e. pole line collapse) and failed switches (i.e. flashovers) will be mitigated. • Storm Hardening will improve safety by mitigating catastrophic pole failures in storm events.

II Pole Renewal

2.1 Investment Description

This section summarizes the proposed investments to address deteriorated poles in Alectra Utilities' overhead distribution system. The specific drivers, needs, and options considered to address these assets are set out in sections 2.2, 2.3, and 2.4, respectively. This investment is the largest single component of the planned Overhead Asset Renewal investments.

Alectra Utilities plans to remediate 1,312 deteriorated poles per year over the five-year DSP term. As described in section 2.4 below, Alectra Utilities believes that this pace of remediation strikes a balance between mitigating public safety risks, ensuring reliability, resource constraints, and the cost of the planned work.

Deteriorated poles in poor or very poor condition will either be reinforced or replaced. Reinforcement is done by adding bracing hardware to support the pole. The reinforcement process and final outcome are shown in Figure A05 - 3.

Figure A05 - 3: Wood pole reinforcement process and final outcome

Reinforcement is typically more cost-effective, and is generally the preferable approach, except in the case of poles that meet any of the following criteria:

- Pole located in a critical location (e.g., highways, train tracks): In these cases, the reduced cost of remediation cannot justify the residual safety risk posed by leaving the pole in-place in the given location.
- Poles carrying equipment (e.g., telecommunication equipment) since the equipment increases the forces on the pole and bracing only provides support to a portion of the pole.[79]
- Pole reinforcement will not remediate safety hazards or slow the deterioration process (e.g. upper part of the wood pole is in poor condition, or significant deterioration of rebar in concrete pole).

Where reinforcement is not a viable option, the deteriorated pole must be replaced. In case of replacing an existing pole, Alectra Utilities must install the new pole in accordance with CSA standards and Ontario Regulation 22/04 (Electrical Distribution Safety). Additionally, associated components on the existing pole that are deteriorated must be replaced. Examples of the associated components are brackets, cross arms, down guys, anchors, ground wires, insulators, arresters, and fasteners. If in any particular case, the pole has transformers, switches, or other equipment with significant remaining life, these are salvaged and re-used.

Table A05 - 3 summarizes the pole renewal forecast expenditures during the term of the DSP 2020-2024, actual historical expenditure in the period 2015-2018, and 2019 as the bridge year.

Table A05 - 3: Pole renewal investment Summary

	Historical Spending				Bridge	Forecast Spending				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$16.2	$20.1	$17.6	$17.1	$17.2	$13.8	$15.3	$16.2	$16.6	$16.7
Primary Driver:	Failure Risk									
Secondary Drivers:	Reliability, Safety, Resilience to Adverse Weather									
Outcomes:	Improved Reliability, Improved Safety, Storm Resilience									

[79] In some cases, poles carrying equipment remediation is possible depending on the type and location of deterioration on the pole, the size of equipment the pole is carrying. For example, if the deterioration is cracks at the location where the equipment is attached, bracing the bottom of the pole will not remediate the pole. Reinforcement is handled on a case by case basis.

2.2 Drivers

The pole renewal investments in this DSP are driven by the need to address deteriorated poles before they fail. Accordingly, the primary driver of these investments is failure risk. Secondary (but no less important) drivers are reliability, safety, and resilience to adverse weather conditions.

The primary and secondary drivers are further defined and summarized in Table A05 - 4.

Table A05 - 4: Investment Drivers

Investment Driver	Reasoning and Investment Benefits
Primary Driver: Failure Risk	The primary driver for these investments is the elevated risk of failure affecting public and worker safety, due to deteriorated wood and concrete poles.
Secondary Driver: Safety	Remediating deteriorated poles will help reduce the significant public and worker safety risk posed by these assets.
Secondary Driver: Reliability	Improved reliability is an expected outcome from performing overhead asset renewal activities, specifically remediating deteriorated poles.
Secondary Driver: Resilience to Adverse Weather Conditions	Although the Storm Hardening investments specifically target resistance to extreme weather events, the pole renewal investment will also make Alectra Utilities' distribution system more resistant to adverse weather conditions.

2.3 Need

This section describes the need to invest in remediating the deteriorated poles in Alectra Utilities' distribution system. The planned pole renewal investment is needed to address two needs: the volume of deteriorated poles on Alectra Utilities' distribution system, and compliance with external standards. Ultimately, both needs lead back to the impact this work will have on customers: maintaining the safety and reliability of the overhead distribution system.

2.3.1 Volume of Deteriorated Poles on Alectra Utilities' Distribution System

Alectra Utilities' wood and concrete poles are a critical component of the utility's distribution system. Alectra Utilities' overhead distribution system includes 105,569 wood poles and 25,340 concrete poles totaling 130,909 poles. Alectra Utilities relies on these poles to support many distribution components such as conductors, transformers, switches, streetlights, and telecommunication attachments. Healthy poles also help ensure the safety of the distribution system, since they provide physical separation between ground level and energized conductors.

Alectra Utilities must assess and monitor the condition of its pole population to ensure that its poles remain in a safe and serviceable condition while meeting prescribed codes for safety and reliability. Alectra Utilities does this through annual pole inspection and testing initiatives.

Alectra Utilities performs pole residual strength testing on wood poles to assess remaining wood fibre strength, which is a key indicator of condition. The pole residual testing is performed in addition to the field inspection for wood poles. Concrete poles are field inspected for deterioration; for example, signs of cracking, concrete spalling (breaking in fragments), and exposed rebar.

Pole inspection and testing initiatives collect pre-defined condition attributes, which are key factors used in determining pole condition and resulting Health Index (HI) score for each pole asset. Figure A05 - 4 and Figure A05 - 5 below set out the condition of the entire population of wood and concrete poles in Alectra Utilities' distribution system, respectively.

Figure A05 - 4: Wood Pole Health Index Demographics

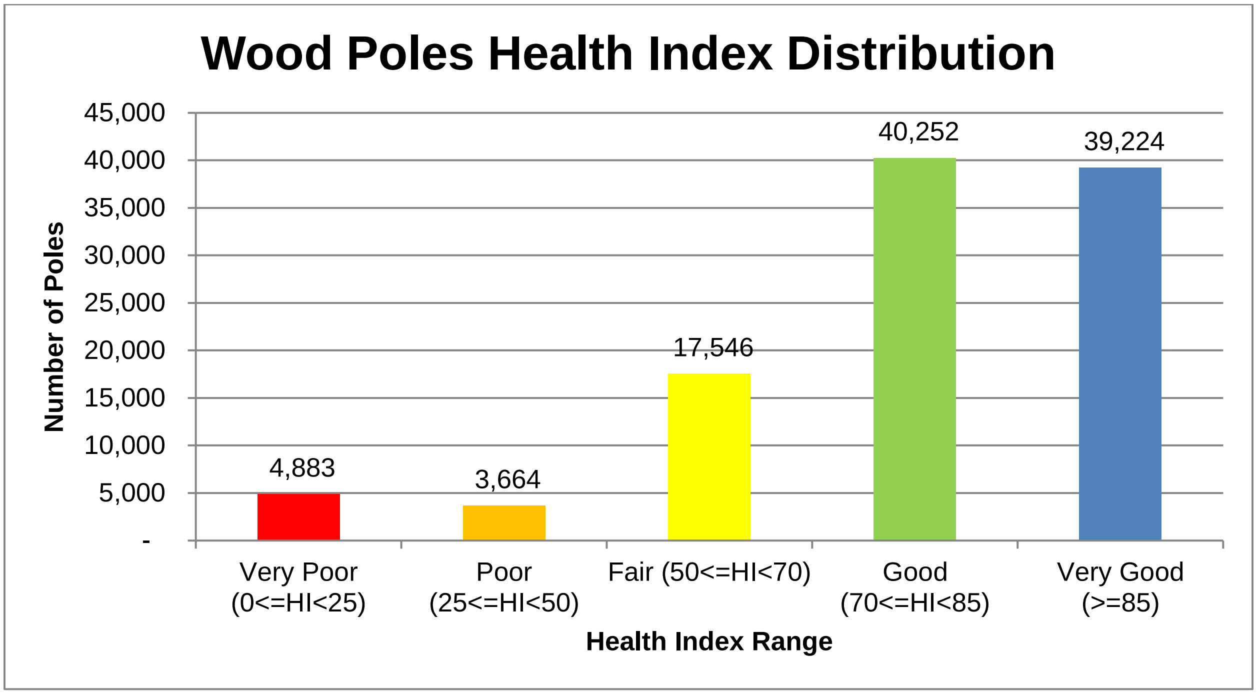
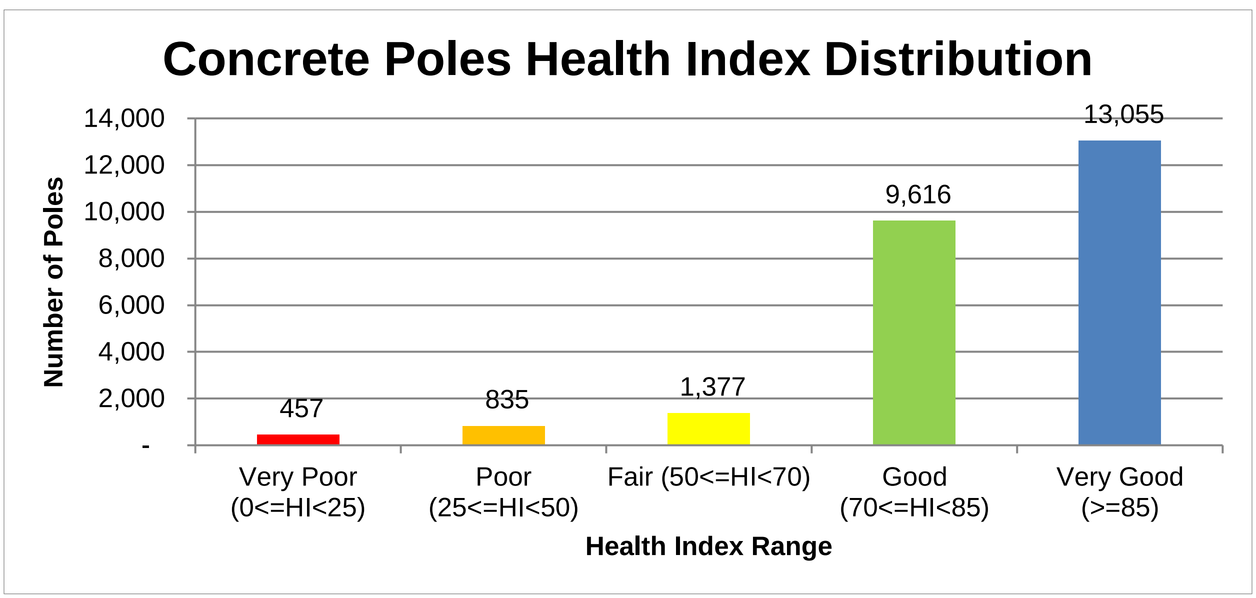


Figure A05 - 5: Concrete Pole Health Index Demographics



These conditions are captured from pole testing (applicable to wood poles) or visual inspections (applicable to wood and concrete poles). Conditions are weighted accordingly in order to produce the Health Index score. Figure A05 - 4 illustrates the HI distribution of the wood poles.

Approximately 8% of the wood poles in Alectra Utilities' service territory are in poor and very poor condition. Figure A05 - 5 illustrates the HI distribution of the concrete poles, where approximately 5% of the concrete poles in Alectra Utilities' service territory are in poor and very poor condition.

The inspection process assesses various aspects of a pole's condition. Key degradation indicators for wood poles include:

- Remaining pole strength;
- 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:

- Rusting/corrosion of the re-bars;
- Cracking;
- Concrete spalling; and
- Mechanical damage.

2.3.2 Compliance with External Standards

Alectra Utilities adopted industry standards from Canadian Standards Association (CSA) in its overhead construction, namely CSA Standard C22.3 No. 1-10 [80]. Clause 8.3.1.3 of the Standard states:

> *"When the strength of a wood pole structure has deteriorated to 60% of the required design capacity, the structure shall be reinforced or replaced"*.

Alectra Utilities is also governed by the Electrical Safety Authority ("ESA") standards, guidance and reporting requirements as part of its compliance. Without the planned pole renewal investment, Alectra Utilities will not adhere to the adopted CSA standards and risks the compliance with ESA and other regulatory entities.

80 "Overhead Systems", CSA C22.3 No. 1-10, Canadian Standards Association.

2.4 Options Analysis

This section describes the alternatives that Alectra Utilities considered for the pace of pole renewal investments.

Alectra Utilities considered three pacing strategies for pole remediation:

- Strategy 1: Renewal of deteriorated assets at the accelerated pace (within 5 years)
- Strategy 2: Renewal of deteriorated assets at a moderate pace (within 7.5 years)
- Strategy 3: Renewal of deteriorated assets at a reduced pace (within 10 years)

Each of the strategies is based on the goal of remediating all of the 9,839 poles currently in poor or very poor condition. The only difference between the strategies is the pace at which that remediation will be done. Table A05 - 5 sets out the three strategies based on the total deteriorated pole population.

Table A05 - 5: Pacing options for pole remediation

Strategy	Plan period (years)	Poles Remediated Per Year			Total Pole Renewal Plan Cost per year ($MM)
		Total	Through Other Investments[80]	Through Pole Renewal	
Strategy 1: Accelerated pace	5	1,968	416	1,552	$27.7
Strategy 2: Moderate pace	7.5	1,312	416	896	$15.7
Strategy 3: Reduced pace	10	984	416	568	$9.7

Alectra Utilities believes that the moderate pace of Strategy 2 strikes the best balance between mitigating public safety risks, resource constraints, and annual cost. This approach results in the replacement of 896 poles per year on average under the pole renewal category, once poles remediated through other investments are accounted for.[81]

The accelerated approach would replace 1,968 poles per year over 5 years. This option mitigates pole failure risk. However, the high volume of work required by this plan would not align to Alectra Utilities' available resources and system constraints, and priority of investment need in underground system renewal.

Strategy 3, reduced pace, mitigates some of the public safety risks within the current planning period; however, it leaves a significant backlog of deteriorated poles at the start of the next five-year period. This option is viable from a resource constraint point of view, mitigates some risks and lowers the spending in the current planning period. However, it is a prelude to higher spending and a more aggressive system renewal plan beyond 2024.

[81] As shown in Table A05 - 5, Alectra Utilities forecasts that approximately 416 poles will be remediated each year through other investments (including Storm Hardening, road widening, voltage conversions, and rear-lot replacements). This amount must therefore be deducted from the total annual number of poles to be replaced to arrive at the number to be replaced under the pole renewal investment.

III Storm Hardening

3.1 Investment Description

This section summarizes the proposed investments to improve the resilience of Alectra Utilities' overhead distribution system to adverse weather events. The specific drivers, need, and options considered to address these assets are set out in sections 3.2, 3.3, and 3.4, respectively.

As described in section 3.3, the planned Storm Hardening investments target a specific population of wood poles carrying four circuits that are particularly susceptible to catastrophic failure in storm and high wind events.

In order to address this issue, Alectra Utilities plans to replace these poles with modern standard poles. These poles will provide the structural load rating required for the application, and will be in compliance with the Canadian Standard Association ("CSA") ice and wind loading standards under non-linear pole loading analysis. Ultimately, through the replacement of these poles, the potentially severe safety risks to the public and employees will be mitigated.

This multi-year project commenced in 2016 and Alectra Utilities is targeting to complete this project in 2030. The quantity of legacy four circuit wood poles remaining in service at the end of 2018 was 950. Alectra Utilities plans to replace these poles at rate of 70 poles annually over the next 12 years.

Figure A05 - 6 and Figure A05 - 7 show the locations of the pole lines composed of wood poles that are at risk of catastrophic failure.

Figure A05 - 6: Locations of Legacy 4-Circuit Wood Pole Lines in the Barrie Area

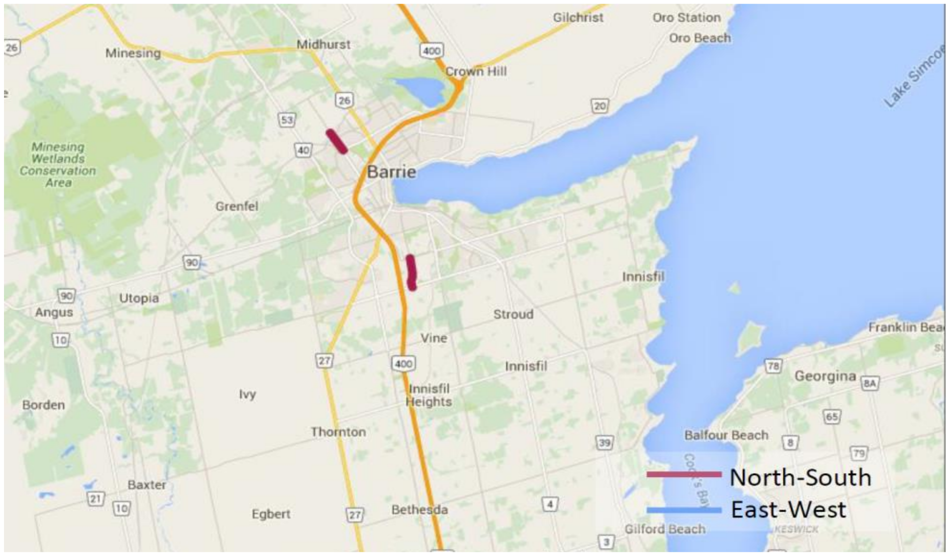


Figure A05 - 7: Locations of Legacy 4-Circuit Pole Lines in York Region

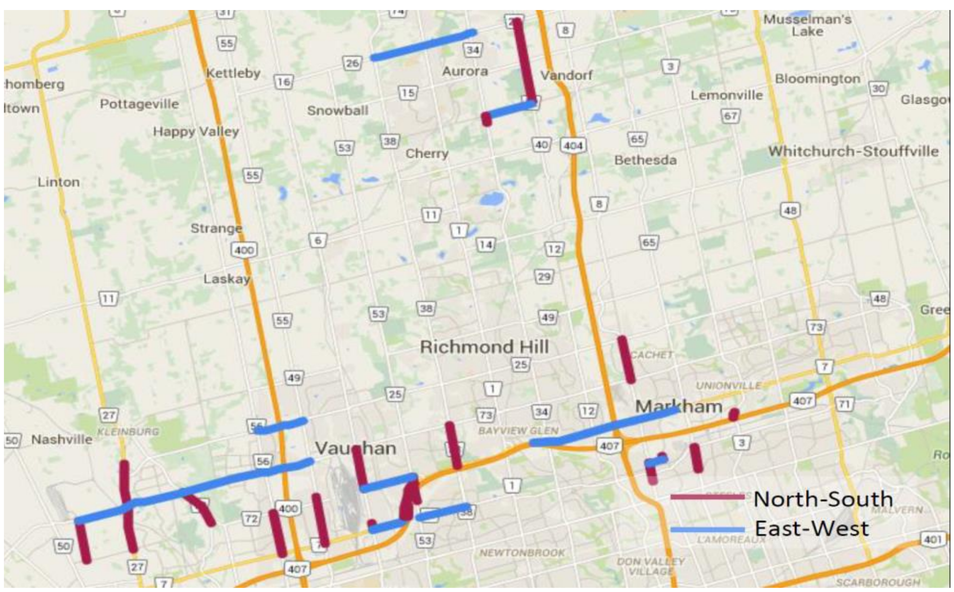


Table A05 - 6 summarizes the outcomes and benefits of the planned Storm Hardening investments.

Table A05 - 6: Summary of Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Customer Value	• Storm Hardening will improve the system resilience in storm events mitigating prolonged outages. • Customers will experience improved safety. Storm Hardening will mitigate potential catastrophic failures of the overhead system in storm events.
Reliability	• Storm Hardening will improve the overhead system resilience to storms by minimizing the impact of storm damage onto the system. • System and feeder-level reliability will be improved through the implementation of Storm Hardening investment projects. • Reliability will be enhanced as deteriorated and functionally obsolete assets are replaced with assets constructed to present day standards as part of the Storm Hardening investments.
Safety	• Storm Hardening will improve safety by mitigating catastrophic pole failures in storm events. • Alectra Utilities plans to realize safety improvements through the construction of new, standardized equipment installed as part of the Storm Hardening investments.

Table A05 - 7 summarizes the forecast Storm Hardening expenditures during the 2020-2024 DSP period, actual historical expenditure in the period 2015-2018, and the 2019 bridge year.

Table A05 - 7: Storm Hardening investment Summary

	Historical Spending				Bridge	Forecast Spending				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$0.0	$1.5	$1.5	$1.4	$1.7	$1.8	$1.9	$2.0	$2.1	$2.2
Primary Driver:	Failure Risk									
Secondary Drivers:	Safety, Reliability, Resilience to Adverse Weather Conditions									
Outcomes:	Customer Value, Reliability, Safety									

3.2 Drivers

The Storm Hardening investments in this DSP are driven by the need to address the specific four-circuit wood poles that may fail catastrophically in adverse weather conditions. Accordingly, the primary driver of these investments is failure risk. Secondary (but no less important) drivers are safety, reliability, and resilience to adverse weather conditions.

The primary and secondary drivers are further defined and summarized in Table A05 - 8.

Table A05 - 8: Investment Drivers

Investment Driver	Reasoning and Investment Benefits
Primary Driver: Failure Risk	The primary driver for these investments is the elevated risk of failure affecting public and worker safety in adverse weather conditions.
Secondary Driver: Safety	Replacing the identified poles will help reduce the significant public and worker safety risk posed by these assets in the event of adverse weather conditions.
Secondary Driver: Reliability	Alectra Utilities expects substantial improvement to reliability from Storm Hardening of specific critical wood poles that support four circuits and are highly susceptible to failure. Due to the high number of circuits and substantial electrical power conveyed through these overhead circuits, Alectra Utilities projects that the risk impact of a failed pole leading to four-circuit outages will be greatly reduced.
Secondary Driver: Resilience to Adverse Weather Conditions	Replacement of specific wood poles carrying four circuit as part of Alectra Utilities' Storm Hardening will improve safety and reliability. Such poles have demonstrated a high susceptibility to catastrophic failure that leads to significant safety risks and prolonged outages.

3.3 Need

The combination of severe weather along with reduced strength can lead to catastrophic failure scenarios where multiple poles lose their structural integrity and fail, possibly falling to the ground. When these poles fail catastrophically, they often cause adjacent poles and the equipment they support, such as transformers, switches etc., to fall to the ground along with them. These poles may fail while employees are working on them and when the public is in close proximity of the asset.

Such failures expose the public to potentially severe consequences, such as exposure to: physical impact, high voltages, and potential environmental hazards as a result of oil filled transformers. Figure A05 - 8 to Figure A05 - 10 are pictures of such catastrophic failures.

Figure A05 - 8: Failure of Legacy Wood Pole on July 17th, 2014

Figure A05 - 9: Failure of Legacy Wood Pole on October 15th, 2017

Figure A05 - 10: High winds caused down power lines on Bayview Avenue in 2018.

While these poles have sufficient strength to perform their standard function in normal operating condition, storms and high wind events can result in high stress on these poles. The high stress in combination with the load of the four circuits results in failure of the pole, which can have a cascading effect on adjacent poles, ultimately resulting in the catastrophic failure of multiple poles. As is evident from the photographs above, such failures expose the public to significant safety risks and prolonged outage events.

3.4 Options Analysis

As described above, the Storm Hardening investments target a particular group of wood poles that do not conform to modern construction standards, and may fail catastrophically during adverse weather conditions. Alectra Utilities considered four options to address the risk posed by these poles:

1. Install periodic in-line and storm guying;
2. Split four circuits into two overhead pole lines;
3. Split four circuits into two underground lines; and
4. Replace with new standardized poles.

Alectra Utilities determined that option four presented the best value. Under this approach, Alectra Utilities will replace the identified poles with new standardized poles.[82] The new poles would retain the existing four-circuit configuration, but would have additional strength that Alectra Utilities expects will be sufficient to withstand the storms and other adverse weather conditions that may occur.

This approach retains some risk. If the new poles were to fail, they would still create a public safety risk, and would still create an effective outage across all four feeders on the pole line. However, this option is the most cost-effective to implement. This option is also the most aesthetically pleasing with every pole being of the same height and standard.

The other options were deficient in various respects.

- Option 1 would not sufficiently resist the adverse weather conditions that Southern Ontario experiences. Although the periodic reinforcement would reduce the risk of cascading pole line failures, the risk of a catastrophic failure would remain unacceptably high.

[82] In some cases, installing a mid-span pole (i.e. a new pole between two existing poles) can be a possible solution for Storm Hardening.

- Option 2 would be significantly more expensive, and would be aesthetically unappealing, as it would effectively double the number of poles in any area where the identified wood poles are currently installed. Moreover, space constraint and municipal by-laws render this option not feasible.
- Option 3 would be even more expensive than option two, as it would involve construction of significant new stretches of underground distribution infrastructure.

IV Switches

4.1 Investment Description

This section summarizes the proposed investments to address deteriorated switches in Alectra Utilities' overhead distribution system. The specific drivers, need, and options considered to address these assets are set out in sections 4.2, 4.3, and 4.4, respectively.

Overhead switches are a distributor's main method of switching loads for system operation and to restore customers after an outage. Switches are the basic tool by which Alectra Utilities can sectionalize and isolate parts of the distribution system when needed.

Alectra Utilities plans to replace deteriorated overhead switches (those that are in poor or very poor condition) on its overhead distribution system at a moderate pace over the term of the DSP. Table A05 - 9 summarizes the forecast overhead switches replacement expenditures during the 2020-2024 DSP period, actual historical expenditure in the period 2015-2018, and the 2019 bridge year.

Table A05 - 9: Overhead Switches Investment Summary

	Historical Spending				Bridge	Forecast Spending				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$1.5	$1.2	$1.0	$0.9	$2.1	$2.1	$2.2	$2.2	$2.3	$2.4
Primary Driver:	Failure Risk									
Secondary Drivers:	Reliability, Functional Obsolescence, Safety									
Outcomes:	Reliability, Safety, Customer Value, Efficiency									

In addition to the deteriorated switches, this investment will target 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 some cases of switch replacements, the new switches will be capable of remote operation and automation, which will have the benefit of reducing outage times for customers. Table A05 - 10 summarizes the outcomes and benefits of the investments planned to address deteriorated switches.

Table A05 - 10: Summary of Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Efficiency	• Renewing deteriorated overhead switches that are deteriorated with automated and remotely operated switches provides Alectra Utilities with the ability to expeditiously restore service, transfer supply and enable isolation from the Control Room, reducing the need to crews to operate switches and permit crews to focus on fault identification and repair.
Customer Value	• Customers will experience improved reliability as a result of the renewal of deteriorated and functionally obsolete assets.
Reliability	• System and feeder-level reliability will be improved through the implementation of the replacement of deteriorated switches. • The replacement of non-functional switches with operational switching points will enhance outage restoration procedures by reducing outage duration, thereby further minimizing customer impacts during an outage event. • Reliability will be enhanced as deteriorated and functionally obsolete assets are replaced with assets constructed to present day standards.
Safety	• Alectra Utilities plans to realize safety improvements through the construction of new, standardized equipment that aligns to current operational practices. For instance, the risks of catastrophic failure associated with degrading poles (e.g., pole line collapse) and failed switches (e.g., flashovers) will be mitigated. • Alectra Utilities will avoid the safety risks of manually operated switch failure through the installation of remotely controlled switches. • The safety risks associated with legacy air-brake switches, which cannot be operated under load (i.e. non-load-break switches) will also be eliminated as these switches are removed from the system. • Storm Hardening will improve safety by mitigating catastrophic pole failures in storm events.

4.2 Drivers

The planned replacement of deteriorated switches in this DSP is driven by the need to address the risk that these assets will fail. Accordingly, the primary driver of these investments is failure risk. Secondary (but no less important) drivers are reliability, safety, and resilience to adverse weather conditions.The primary and secondary drivers are further defined and summarized in Table A05 - 11.

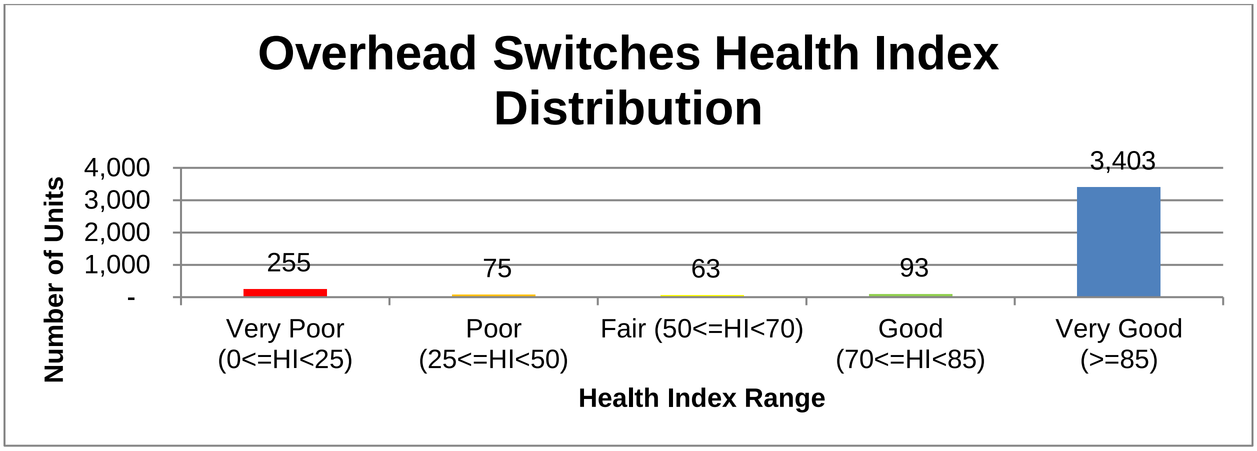
Table A05 - 11: Investment Drivers

Investment Driver	Reasoning and Investment Benefits
Primary Driver: Failure Risk	The primary driver for these investments is the elevated risk of failure affecting worker safety, due to deteriorated switches, as well as the elevated risk of failure associated with specific switch assets that are not fit to operate.
Secondary Driver: Safety	Replacing deteriorated or unfit switches mitigates worker safety risks posed by those assets. When switches cannot be relied on to operate properly, it can be harder to de-energize parts of the distribution system. Also, deteriorated switches introduce flashover risk that pose a safety risk to crews that must operate them.
Secondary Driver: Reliability	Alectra Utilities expects that replacing deteriorated switches with improve the reliability of the overhead distribution system, as it will allow the utility to sectionalize the system and restore power to customers more efficiently. The replacement of legacy switches with modern standard assets, including those that allow remote and automated operation, will further enhance reliability.
Secondary Driver: Functional Obsolescence	Obsolete asset types, such as non-load-break air-break switches, will be replaced through these investments. Replacement of these assets is expected to improve reliability.

4.3 Need

As shown in Figure A05 - 11, there is a small but significant population of 330 deteriorated switches (those in poor and very poor condition) across Alectra Utilities.

Figure A05 - 11: Overhead Switches Health Index Distribution



As discussed in section 4.4 below, Alectra Utilities must address this population of deteriorated switches at an appropriate pace. Failure to replace these assets would result in increased safety risks and decreasing reliability.

Alectra Utilities has a switch maintenance initiative as part of its asset life cycle optimization (refer to section 5.3.3). The initiative allows switches to operate as intended in safe and reliable manner to achieve their expected useful life.

4.4 Options Analysis

Alectra Utilities considered three pacing options for address the deteriorating switches:

- Strategy 1: Renewal of deteriorated assets at the accelerated pace (within 5 years)
- Strategy 2: Renewal of deteriorated assets at a moderate pace (within 7.5 years)
- Strategy 3: Renewal of deteriorated assets at a reduced pace (within 10 years)

The strategies are detailed in Table A05 - 12.

Table A05 - 12: Overhead switches pacing options

Strategy	Plan period (years)	Switches Remediated Per Year			Total Switch Renewal Plan Cost per year ($MM)
		Total	Through Other Investments	Through Switch Renewal	
Strategy 1: Accelerated pace	5	66	9	57	$3.0
Strategy 2: Moderate pace	7.5	44	9	35	$2.2
Strategy 3: Reduced pace	10	33	9	24	$1.3

Alectra Utilities believes that the moderate pace of Strategy 2 strikes the best balance between mitigating safety risks, reliability impacts, resource constraints, and annual cost. This approach results in the replacement of 35 overhead switches per year on average under the overhead switch renewal category, once switches remediated through other investments are accounted for.[83]

The accelerated approach would replace 66 switches per year over 5 years. While this approach mitigates switch failure risk, the high volume of work required by this plan would not align to Alectra Utilities' available resources and system constraints. For these reasons, Strategy 1 remains largely impractical to execute.

Strategy 3, reduced paced replacement, mitigates some of the public safety risks and reliability impacts within the current planning period; however, it leaves a significant backlog of deteriorated assets that are critical to the operation of the overhead system at the start of the next five-year period. This option is viable from a resource constraint point of view, mitigates some risks and lowers the spending in the current planning period. However, it is a prelude to higher spending

[83] As shown in Table A05 - 12, Alectra Utilities forecasts that approximately 9 switches will be added to the system each year through switch automation initiative investment. This amount must therefore be deducted from the total annual number of switches to be replaced to arrive at the number to be replaced under the switch renewal portfolio.

and a more aggressive system renewal plan beyond 2024 while incurring reliability risks within the current planning period.

V Insulators Prone to Failure

5.1 Investment Description

This section summarizes the proposed investments to address certain insulators in Alectra Utilities' overhead distribution system that are prone to failure. The specific drivers, need, and options considered to address these assets are set out in sections 5.2, 5.3, and 5.4, respectively.

Alectra Utilities' overhead distribution system contains a population of legacy porcelain insulators as well as, first-generation polymeric insulators.[84] The design of these insulators has led to safety issues for Alectra Utilities' crews and reliability issues for the overhead distribution system. Alectra Utilities proposes to replace these insulators during the term of the DSP.

The planned investment level to replace the identified insulators is shown in Table A05 - 13

Table A05 - 13: Insulator investment summary

	Historical Spending				Bridge	Forecast Spending				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$0.6	$1.1	$1.2	$0.8	$0.9	$0.8	$0.7	$0.7	$0.7	$0.7
Primary Driver:	Failure Risk									
Secondary Drivers:	Reliability, Safety									
Outcomes:	Reliability, Safety									

Table A05 - 14 summarizes the outcomes and benefits of the investments planned to address deteriorated poles.

[84] Referred to as ““non K-line” insulators.

Table A05 - 14: Summary of Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Reliability	• System and feeder-level reliability will be improved through the replacement of the identified insulators. • Reliability will be enhanced as deteriorated and functionally obsolete insulators are replaced with assets constructed to present day standards.
Safety	• Alectra Utilities plans to realize safety improvements through the construction of new, standardized insulators that aligns to current operational practices. Replacing the identified insulators will reduce the safety risks (e.g., pole fires and failed poles) due to failed insulator

5.2 Drivers

The insulator investments are driven by the need to replace the identified insulators that are prone to fail. Accordingly, the primary driver of these investments is failure risk. Secondary (but no less important) drivers are safety, reliability, and resilience to adverse weather conditions.

The primary and secondary drivers are further defined and summarized in Table A05 - 15.

Table A05 - 15: Investment Drivers

Investment Driver	Reasoning and Investment Benefits
Primary Driver: Failure Risk	The primary driver for these investments is the elevated risk of failure affecting public and worker safety, due to the deterioration of the identified insulators.
Secondary Driver: Reliability	Replacement of the identified insulators is expected to improve reliability.
Secondary Driver: Safety	Porcelain insulators can result in wood pole fire, which are hazardous. These events can cause pole failures, potentially putting the public and crews in contact with equipment that may fall and in extreme cases energized conductors falling to ground.

5.3 Need

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 A05 - 12 and Figure A05 -

13 show the loss of pole structure and pole failures caused by tracking insulators and resulting pole fires.

Figure A05 - 12: Wood Pole Fire Resulting from Tracking Insulators

Figure A05 - 13: Pole Failure Resulting from Tracking Insulators

5.4 Options Analysis

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. This is an ongoing multi-year project.

Given the relatively small cost of replacing the identified insulators, and the significant benefit that will result, Alectra Utilities has not considered any option other than the proposed replacement of these assets at the pace proposed.

IV Investment Projects

The material investments from 2020 to 2024 that form the deteriorated assets and assets prone to adverse weather investments are included in Table A05 - 16.

Table A05 - 16: Material Projects and Initiatives

Project Code	Project Name	CAPEX ($MM)
100867	Pole Renewal	$78.6
101027	Switch Renewal	$11.2
103659	Storm Hardening - Four-Circuit Poles	$9.9

Part B: Voltage Conversion Projects

I Overview

During the DSP period, Alectra Utilities plans to address deteriorated substation equipment operating on legacy voltages (4.16 kV and 8.32 kV) and upgrading feeder assets to the current distribution voltages (13.86 kV and 27.6 kV) through Voltage Conversion. Legacy voltages were utilized in the 1950s and are found in pockets within the distribution system. The legacy voltages are mainly surrounded by current primary voltage levels. Feeders operating with a specific voltage can only be backed up from tie-points of the same voltage, loading permitted.

The Voltage Conversion investment involves decommissioning the legacy 4.16kV and 8.32kV sub-station assets and utilizing the primary voltage that feeds these substation as the distribution voltage to deliver power to customers. The voltage conversion process leverages existing distribution assets that meet the current codes and standards of the new voltage level. During the Voltage Conversion projects select distribution assets will be replaced: The assets that will be replaced in Voltage Conversion projects consist primarily of:

- Poles that do not meet the height and strength requirement;
- overhead switches and insulators that are not rated for use at the new voltage;
- distribution transformers that do not have the functionality to operate at the new voltage; and
- legacy overhead conductors.

By addressing these deteriorated substation assets with modern voltage systems, Alectra Utilities will improve safety, system resilience, and efficiency of the distribution system.

Deteriorated station assets pose a significant failure risk. Station assets are managed proactively as they deteriorate and are not operated on a run-to-failure basis due to the criticality and consequence of failure. In addition, to station assets, deteriorated distribution assets on the existing lower-voltage infrastructure poses safety risks. Legacy voltage are predominantly overhead construction. When overhead equipment fails, there are consequential impacts on safety risks due to downed power-lines, pole fires and other factors.

From a functional perspective, legacy voltages can pose significant safety risk. For example, protective equipment on legacy voltages, in some cases, might not recognize a wire down, resulting in a live conductor within the public's reach.

By eliminating legacy voltage level and utilizing the primary voltage of a substation in the distribution of electricity, system resilience is improved by allowing for more back-up tie-points that facilitate system restoration and planning.

The locations of the Voltage Conversion investment include:

- Alectra West Voltage Conversion, including feeders in Downtown Hamilton, Stoney Creek and Hamilton Mountain locations;
- Alectra Central North Voltage Conversion, including conversion of feeders in Brampton; and
- Alectra Central South Conversion, including conversion of feeders in the Bromsgrove/Clarkson area.

Table A05 - 17: Voltage Conversion Summary

	Historical Spending				Bridge	Forecast Spending				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$12.5	$10.1	$20.0	$17.8	$19.3	$11.1	$9.9	$13.4	$4.4	$10.6
Primary Driver:	Failure Risk									
Secondary Drivers:	Functional Obsolescence, Reliability									
Outcomes:	Reliability, Safety, Efficiency, Other Benefits									

II Investment Description

During the DSP period, Alectra Utilities plans to convert deteriorated substation assets operating at the legacy 4.16 kV and 8.32 kV system primary voltages to the modern standardized 13.8 kV or 27.6 kV primary voltage class.[85] The 4.16 kV and 8.32 kV distribution systems were constructed in the 1950s and are among the oldest distribution assets in Alectra Utilities' distribution system. Currently, these legacy voltages are found in pockets within the distribution system surrounded by the modern voltages as shown in Figure A05 - 14 and Figure A05 - 15. Replacing these assets with modern infrastructure will address failure and safety risks, reliability risks, system resiliency, and create operational and system efficiencies.

Through the Voltage Conversion investment, Alectra Utilities plans to decommission substations that have deteriorated and pose a significant failure and safety risks with legacy voltages. Moreover, distribution assets will be upgraded to operate on the current primary voltages and reconfigured to provide system reliability and resiliency. Reliability and resiliency benefits are facilitated by the elimination of legacy voltages and use the substation source voltage as the distribution voltage, allowing for more system backups and tie-points. The reconfiguration will provide looped/switchable configurations[86]. Re-configuring the distribution system in an area can substantially reduce reliability risks to customers and improve system resilience, as future outages can be further limited to smaller groups of customers, and restoration procedures can be executed within a shorter period of time. System resiliency provides operational benefits by allowing operators to have more options to shift loads to maintain optimal operation of the distribution system during system peaks.

The negative impacts of legacy lower-voltage equipment affect pockets of Alectra Utilities customers. Most of the utility's customers are served from feeders that operate at the 13.8 kV and the 27.6 kV primary distribution voltage levels. Approximately 75,700 customers are served from feeders operating at the 4.16 kV and 8.32 kV primary voltage levels. These areas include 23

[85] The substation assets addressed in the Voltage Conversion investments are in Poor or Very Poor condition, or are functionally obsolete. Overhead assets encountered during the upgrade process will be salvaged (to be reused) if the are in good condition and can be used on the current primary voltages else they will be replaced.

[86] Radial configuration is a legacy design for feeder lines. While initially less expensive to build, the radial configuration has limited backup provisions restricting the utility's ability to restore power during a planned or a contingency event, resulting in longer outages to customers.

substations in Hamilton, 3 substations in Brampton, 25 stations in Mississauga and 16 stations in Barrie. These station were installed in the 1950's and their condition has deteriorated and there is scarcity of available spare parts. There is also a higher probability of unanticipated outages as a result equipment failure due to the deterioration. Also, some parts of the distribution system within the 4.16 kV and the 8.32 kV voltage levels are being operated at maximum capacity with restricted backup capabilities in the event of unplanned outages.

The projects planned for the DSP period will replace lower-voltage assets in four communities: Brampton, Mississauga, Hamilton and Stoney Creek. Over the DSP period, Alectra Utilities plans to replace approximately 95 km of lower-voltage lines and upgrading approximately 11,000 customers to higher-voltage service.

Figure A05 - 14 and Figure A05 - 15 depict the lower-voltage systems in Hamilton and Brampton showing the pockets of 4.16 kV and 8.32 kV surrounded by 13.8 kV or 27.6 kV.

Figure A05 - 14: Low Voltage System - Hamilton

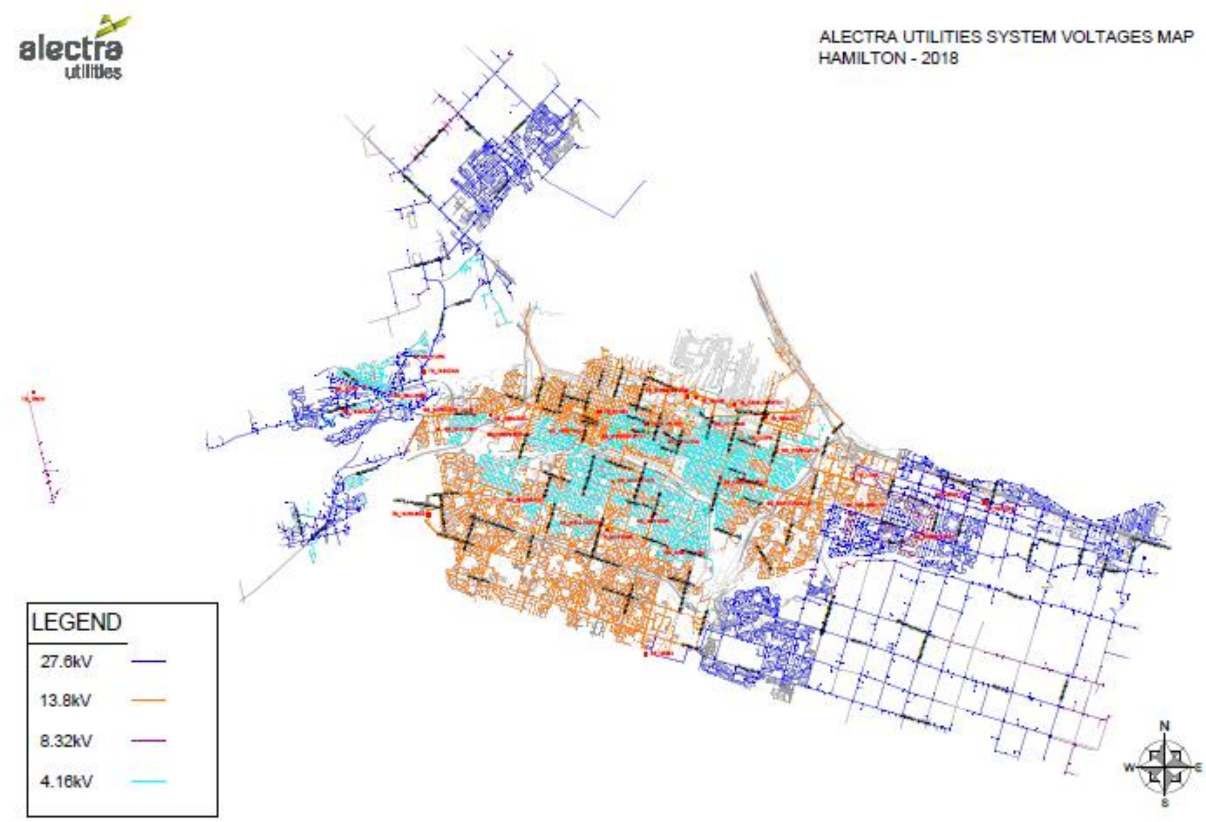
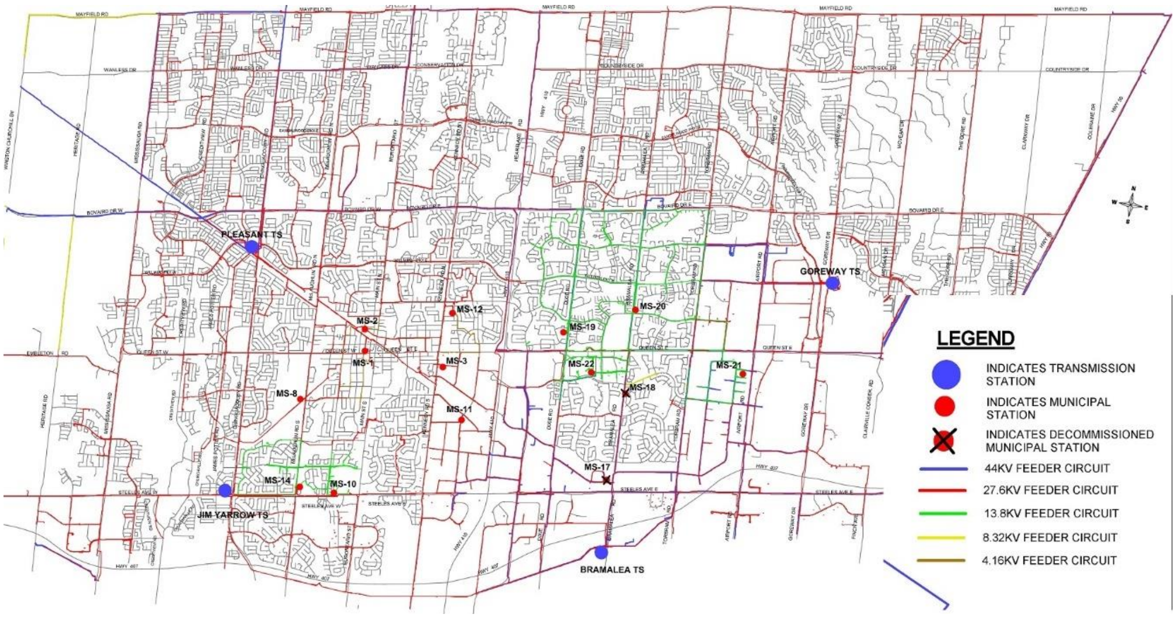


Figure A05 - 15: Low Voltage System - Brampton



In addition to improving reliability, these investments will mitigate safety risks and create efficiencies. Replacing deteriorated lower-voltage assets improves safety since modern assets adhere to current safety codes. Moreover, in case of wire-down scenario, current standard voltages enable protective equipment to recognize the event of wire down and remove the voltage from the lines. In some scenarios, protective equipment on legacy voltages might not recognize the wire-down event, resulting in an energized conductor endangering the public safety and property.

Converting to modern voltages will also create efficiencies, since this eliminates the need for having a utility owned substation, hence, avoiding ongoing capital and maintenance costs. By decommissioning substations, the maintenance and inspection costs are eliminated in perpetuity. Since modern voltages are higher voltages compared to the legacy voltages, they can distribute more power to more customers requiring less station capital investments to meet new customer connections. Moreover, higher voltages reduce line losses, thus providing a perpetual conservation by reducing losses.

2.1 Summary of Investment Outcomes and Benefits

Table A05 - 18 summarizes the outcomes and benefits associated with Voltage Conversion Projects.

Table A05 - 18: Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Reliability	• Reliability will be enhanced for customers transferred from legacy 4.16 kV or 8.32 kV feeders to the standard 13.8 kV or 27.6 kV feeder design, due to the enhanced tie points and contingency capabilities that these feeders offer when compared to the radial design of the legacy feeders. • Additional feeder ties built at 13.8kV feeders (4kV areas are removed allowing continuous 13.8kV voltage level, thus providing increased feeder ties for flexible load transfers and resiliency) • Replacing non-functional switches with working switching points will enhance outage restoration procedures, thereby further minimizing customer impacts during an outage event. • Removal of wooden cross arms and pins removes the risk of pole fires.
Safety	• Safety improvements will be realised through the installation of new, standardized equipment that aligns to current operational practices. • Through the installation of SCADA-enabled switches, the safety risks associated with manual load-break switch operation can also be avoided. • Removal of porcelain insulators and switches which are prone to contamination and failure. • Reducing the risks of having energized wire-down events in case of conductor failure.
Efficiency	• These investments will provide financial and operational benefit by decommissioning of the lower-voltage substations. For example, eliminating the maintenance and inspection of the decommissioned sub-stations assets.

Outcome	Investment Benefits and Objectives
	• The addition of new switching points on existing feeders will optimize the restoration procedures by which crew workers in the field and/or power system controllers in the control room are able to operate switching devices in order to perform sectionalisation, isolation and restoration procedures. • Higher voltages can accommodate more customers and feeder can go longer distances. • These investments will lower line losses due to conversion to higher voltage class.
Other Benefits	• Logistic benefits related to reducing parts needed in inventory when eliminating lower voltage class equipment from system.

III Investment Drivers and Need

3.1 Purpose

The purpose of the planned Voltage Conversion investments is to create long-term value for Alectra Utilities and its customers by replacing deteriorated 4.16 kV and 8.32 kV distribution assets with modern, higher-voltage equipment. The lower-voltage substation assets that will be replaced through Voltage Conversion investments are the oldest in the distribution system and must be renewed in the DSP period. By decommissioning these assets and converting the system to a higher-voltage equipment that meets present-day safety and performance standards, Alectra Utilities can mitigate the failure and safety risks and improve system resilience and gain efficiencies.

Converting to higher voltage distribution allows Alectra Utilities to decommission some older stations that would otherwise need to be renewed and maintained. Like-for-like renewal of lower-voltage assets would increase Alectra Utilities' stations capital requirements during the first three years of the DSP period by approximately $22M.

In addition, Alectra Utilities believes that at a minimum 50% or $25.9M of the voltage conversion investments would still be required to resolve urgent distribution system issues. The cost estimate above is assuming no reactive failures occur prior to the planned work which, at a minimum, doubles the cost. Halting voltage conversion would result in the loss of any additional benefits such as:

- Reduction in OPEX costs (from eliminated station maintenance);
- Increased reliability from feeder ties at 13.8 kV for both 4 kV customers and customers already on 13.8 kV feeders;
- Automation (reduction in outage duration) for legacy 4 kV customers and some 13.8 kV customers;
- Reduction in reactive costs triggered by asset failure; and
- Reduction in line losses.

If Alectra were to renew the deteriorated lower-voltage assets without converting to a higher voltage, it would lose the opportunity to economically transition to higher voltage equipment for a long period.

Alternatively if Alectra Utilities decided to take an opportunistic approach, where only during rebuilds would conversion take place, in a piece-meal style approach, this would actually introduce more risk to customers. Stations in general are normally backed up by one or more stations in the same geographical area. Similarly feeders themselves are also backed up by other feeders in the surrounding geographical area. Removing any feeder as part of a rebuild could create gaps in the resiliency of the network and increase the risk and exposure to the remaining customers to prolonged outages.

Neither of these approaches, deferring conversion or an opportunistic piece-meal approach are prudent and therefore conversion must be completed in a planned manner in order to minimize risk and maximize benefit.

Alectra Utilities' planned Voltage Conversion investments have been aligned to ensure that, in the majority of cases, any non-deteriorated assets can be reused when conversion occurs. For example, in the Alectra West operational area, practices call for the installations of a dual voltage transformers. These transformers can be reused when the higher 13.8kV voltage feeders are installed. Similarly, taller poles are installed to accommodate future installation of more circuits at a higher ground clearance.

The primary and secondary drivers are further defined and summarized in Table A05 - 19.

Table A05 - 19: Investment Drivers

Investment Driver	Reasoning and Investment Benefits
Primary Driver: Failure Risk	Deteriorated station assets pose a significant failure risk. Station assets are managed proactively as they deteriorate and are not operated on a run-to-failure basis due to the criticality and consequence of failure. Oil filled breakers are no longer manufactured and spare parts can not be found. Operationally they pose a significant safety risk to staff and as such they are required to wear bomb-suits in order to even enter the station if the equipment is active. Legacy distribution infrastructure associated with low-voltage feeders are functionally obsolete. These older, lower-voltage systems use smaller-diameter wood poles that are weaker than modern wood or concrete poles. These poles are ultimately more susceptible to failure during severe weather events. The use of wood cross arms and pins instead of modern armless construction increases likelihood of pole fires, and wire downs. The use of porcelain insulators on switches are known to be prone to failure in contrast to modern polymer insulators and switches.
Secondary Driver: Reliability	The primary driver for these investments is the elevated risk of failure, due to the deteriorating overhead infrastructure, as well as deteriorating substation infrastructure. In conjunction with the primary driver of Failure Risk, Alectra Utilities expects that reliability will improve from performing voltage conversion projects and other overhead asset renewal investments. In particular, the voltage conversion of 4.16 kV and 8.32 kV feeders is expected to enhance the security of supply, not only due to the robust substations that supply the 27.6 kV feeders, but also due to the enhanced contingency and availability of tie points at this voltage level**.**
Secondary Driver: Function Obsolescence	The stations assets associated with the low voltage are obsolete. This equipment is not supported by manufacturers, meaning that parts have to be re-used from other older assets, which poses operational issues if the equipment has to be taken out of service for extended periods of time to custom fit replacement parts.

3.2 Asset Details

3.2.1 Overview of targeted assets

Assets in the Voltage Conversion investment fall into two categories:

- Substation assets (discussed in section 3.2.3)[87]; and
- Distribution assets (discussed in section 3.2.2)

The priority projects for voltage conversion are the substation assets as failure of a critical component, such as the switchgear bus, can cause a major outage for an extensive timeframe impacting a large number of customers. Furthermore due to system design and construction in the 1950's, feeder redundancy is minimal and loss of a station would result in stranded load and increased cost as generators would be required. Alectra Utilities has an extensive maintenance program in place to manage substation assets, which has allowed facilities to operate past their typical useful life. However, no amount of maintenance can overcome obsolescence. This is most pronounced in the circuit breaker category, where the majority of breakers for stations identified for conversion in this DSP have been identified as obsolete.

Downtown Hamilton Area:

- Aberdeen Station: Voltage conversion at the station is partially complete. Breakers are obsolete and in Poor condition. Operational issues with rear lot construction on some feeders.
- Central Station: Voltage conversion at the station is partially complete. Breakers are obsolete and oil-filled, they can longer be maintained, and operationally require the station to be taken out of service if any interaction with staff is required. Safety concerns with category 4 arc flash rating within station.

[87] While Alectra Utilities also plans to replace assets in these categories through other capital portfolios during the DSP period, there is no overlap between the assets planned for replacement in those portfolios and in the Voltage Conversion projects.

Stoney Creek Area:

- Deerhurst Station: 2 of 3 feeders have been decommissioned due to reclosers being non-functional. Loads have been permanently transferred to last remaining feeder in anticipation of the future conversion.
- Dewitt Station: Transformer is in Poor condition and has had a history of failures. Reclosers are in Poor condition.
- Galbraith Station: Switchgear and breakers are in Poor condition. Transformer has required repairs recently.

Hamilton Mountain Area:

- Eastmount Station: Breakers are obsolete and in Poor condition. Recurring issues with electromechanical relays. Operational issues with rear lot construction on some feeders.
- Elmwood Station: Breakers are obsolete and in Poor condition. Recurring issues with electromechanical relays. Several pole hardware issues due to wood cross arms and pins.

Brampton Area:

- MS12 Station: Breakers are obsolete and in Poor condition.
- MS2 Station: Transformer has high DGA values, Breakers are in Good condition and new[88], but recently had an issue with the breaker's control card that required the entire station be taken out of service while the cards were replaced.
- MS8 Station: Transformer is leaking oil, investment deferred due to imminent voltage conversion. Partial conversion completed, only one feeder remains in service.

Mississauga:

- Clarkson Station: Operational issues with rear lot construction on some feeders, and direct buried cables.

[88] Alectra Utilities will re-use as many assets in good condition or better as is realistically possible

Voltage Conversion of stations occurs over multiple years (or phases) based on the number of feeders and geographical service area of the station in question. Alectra Utilities and its predecessors have been actively engaged in voltage conversion projects.

Substation Assets

Many of the legacy substation equipment categories included in the Voltage Conversion projects are:

- No longer supported by the manufacturer;
- Parts are difficult to come by or must be custom made;
- Difficult or costly to maintain;
- Functional and Operational Obsolesces; (e.g. safety restrictions on operation circuit breakers)
- Unable to meet current safety standards (e.g., switchgears that are not arc resistance);
- Unable to meet current performance standards
- Sources of environmental risks (e.g., lacking spill containment or contain hazardous substances); or
- Otherwise lacking modern monitoring capabilities.

Alectra Utilities harvests serviceable assets during voltage conversion so as to strengthen the reliability and operability of the remaining station assets by having a supply of available power transformers or circuit breakers for redeployment in the event of an unplanned failure in other compatible stations. Power transformers represent a long-lead and higher capital cost item, and harvesting these units as spares works to benefit the customers and ratepayers by re-using assets already within the system.

Harvesting serviceable assets ultimately avoids costs that would otherwise be required, since Alectra Utilities would have had to otherwise buy new power class transformers. Instead of making significant renewal expenditures Alectra Utilities is able to maintain the poor and very poor station assets because conversion of stations creates in some cases additional spares for the remaining lower-voltage stations. While Alectra Utilities strives to maximize the value of harvested assets, such assets are nonetheless vintage equipment that has been in service. This equipment will not have the same functional lifespan as new equipment. Accordingly, Alectra Utilities will ultimately see diminishing returns from this practice.

3.2.2 Feeder Assets

Since there are a large population of feeder assets, the condition of feeder assets tends to be diverse. While the overall condition shows the average, this can be a case of diverse populations masking the impact of deteriorated assets. If the Voltage Conversion projects were not to proceed, significant renewal investments would still be required to renew these deteriorated assets as part of the Overhead Renewal investment. Even if the assets in the worst condition were replaced, the rest of the system would continue to deteriorate and continue to pose reliability risk and eventually need to be replaced.

Some lower-voltage feeder assets already share poles with the higher-voltage circuits that will be used for conversion. Accordingly, Alectra Utilities has placed less weight on the condition of feeder assets when prioritizing voltage conversion projects.

IV Investment Timing and Pacing

4.1 Summary of Expenditures

Table A05 - 20 provides the year-over-year breakdown of voltage conversion investments, including the historical period from 2015-2018, the bridge year in 2019, and the future period from 2020-2024.

Table A05 - 20: Historical and Proposed Investment Spending

	Historical Spending				Bridge	Forecast Spending				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$12.5	$10.1	$20.0	$17.8	$19.3	$11.1	$9.9	$13.4	$4.4	$10.6

4.2 Historical Expenditures (2015-2019)

Historical expenditures between 2015 and 2019 total $79.7MM. These expenditures have remained mostly flat over the years with only additional expenditures taking place in 2017 to 2019. This increase was due to the overlapping timing of Voltage Conversion projects being completed (St. Catharines area, West Hamilton area) while others were ramping up that were deemed the next priority (Dundas area) in 2019.

The majority of the expense in the historical years has been in Alectra Utilities' Western operational area, where the legacy utility had a Voltage Conversion in place since 2009. Since 2009, the Western operational area has fully converted ten substations (Webster MS, Halson MS, Caroline MS, Hughson MS, Stroud's Lane MS, Whitney MS, Taylor MS, Vine MS, Grantham MS, Welland MS) and partial converted four substations (Aberdeen MS, Central MS, Highland MS, John MS). In Brampton, MS1 has been fully converted.

4.3 Future Expenditures (2020-2024)

Future expenditures between 2020 and 2024 total $49.4MM.

Alectra Utilities' planned Voltage Conversion spending level reduces to a relatively consistent year-over-year pace in 2020. The utility plans to continue sustained investment at this level is proposed in order to carry the voltage conversion work to completion.

4.4 Investment Pacing and Prioritization

Alectra Utilities prioritizes and paces voltage conversion projects based on needs, values and risk identified in business case for each area. The overall pacing has been determined by taking into consideration the following factors

- Asset Condition – Station
- Asset Age
- System Configuration and Capacity
- Co-ordination with other Capital and Maintenance Work Programs
- Criticality and Customer Impact

Alectra Utilities utilizes a multi-variable capital investment optimization tool (Copper Leaf C55) to optimize projects based on values and risk across the entire capital investment portfolio for the DSP period. The projects identified are optimized based on the available funding and the values and risk in the given year.

4.5 Execution Approach

Alectra Utilities will leverage internal and external contractors to complete the design and construction of the new overhead infrastructure to be installed within the system. Alectra Utilities has retained external contractors working at different work sites throughout the year under a multi-year procurement construction Master Service Agreement. Regular progress meetings are held to ensure technical and operational issues are resolved promptly.

The Execution phase will follow Alectra Utilities' internal project management methodology which provides specific guidelines, procedures, work instructions, and industry best practices that allow the project work to be performed in an economically efficient, cost effective, and safe manner.

V Options Analysis

Alectra Utilities has considered different options for each of the major asset classes being treated in this investment. The following subsections provide further information on the different options that were considered.

5.1 Overhead Voltage Conversion

For legacy overhead assets connected to the 4.16 kV and 8.32 kV system voltages respectively, three different intervention strategies have been considered:

- Strategy 1: Status Quo / Run to Failure
- Strategy 2: Like-for-like replacement of existing assets with new assets at the same voltage ratings
- Strategy 3: Full conversion of the lines to new 13.8 kV or 27.6 kV primary system voltages

Under the status quo option, Alectra Utilities would only replace these legacy assets should they fail reactively. Under this scenario, there would be no opportunity to convert these assets to the standardized voltage levels, as assets would have to be replaced in a like-for-like manner. Replacing assets reactively tends to lead to the highest per-unit cost, and greatest impact to customer outage times. Furthermore, the reliability and safety risks associated with this infrastructure would continue to persist. Alectra Utilities would also be required to continue to maintain, and possibly replace or upgrade the legacy substations that supply these lower voltage levels, as many of the breaker assets have reached functional obsolescence and there are no parts available.

Under the like-for-like replacement option, existing 4.16 kV and 8.32 kV infrastructure would be replaced with new 4.16 kV and 8.32 kV infrastructure respectively. This approach is very similar to the status quo option, with the exception that customer outages can be avoided by replacing assets before they fail. By planning ahead to perform the replacements, the added benefit of like-for-like over the status quo is lower per-unit costs given that multiple assets can be addressed at a time. However, by keeping these system voltages intact, the functional obsolescence issues associated with these assets will continue to persist and eventually significant substation investments will be required. Should a future outage occur, it will likely be longer and create a larger customer impact, due to the lack of contingency options available at these voltage levels.

The third strategy is full conversion to 13.8 kV or 27.6 kV system voltage. Renewal investments already would need to be undertaken based on the asset health condition for many of the station assets, poles and distribution transformers. Under this alternative, assets will be aligned to modern standards and practices. Unification of voltage levels across large sections of the system further improves the operability and should lead to reliability gains. Converting to higher-voltages will also create opportunities for Alectra Utilities to reconfigure the grid to add new switching points and automation, and to phase-out trouble areas like rear-lot construction. These improvements will allow Alectra Utilities to improve service to customers by conducting isolation, sectionalizing and restoration activities much faster. The full conversion option presents the best value long-term by having conversion completed in a planned manner while also avoiding the substation investment costs, as well as benefits to the operability of the system, which ultimately benefits the customers. For these reasons, Alectra Utilities selected this approach.

VI Investment Projects

The material investments from 2020 to 2024 that form the Voltage Conversion investments are included in Table A05 - 21.

Table A05 - 21: Material Projects and Initiatives

Project Code	Project Name	CAPEX ($MM)
150317	Voltage Conversion - Deerhurst MS, Hamilton	$7.8
151139	Voltage Conversion - MS-12 Hansen Rd, Brampton	$5.5
150352	Voltage Conversion - Central MS_2020 to 2022, Hamilton	$5.0
151138	Voltage Conversion - MS-2 Church St, Brampton	$4.4
150320	Voltage Conversion - Dewitt MS , Hamilton	$4.1
150354	Voltage Conversion - Eastmount MS, Hamilton	$3.8
150351	Voltage Conversion - Aberdeen MS_2020 to 2022, Hamilton	$3.3
150321	Voltage Conversion - Galbraith MS, Hamilton	$3.3
150355	Voltage Conversion - Elmwood MS, Hamilton	$2.8
150356	Voltage Conversion - Clarkson Area, Mississauga	$2.7
150377	Voltage Conversion and Rear Lot - Montgomery Dr, Hamilton	$1.8
100319	Radial Supply Remediation/Conversion - 13.8 kV to 27.6 kV on Miller Ave	$1.5

Appendix A06 - Reactive Capital

I Overview

Through the Reactive Capital portfolio, Alectra Utilities addresses assets that have either failed or are at high-risk of failing or causing safety issues. Capital work may be required on a reactive basis in a variety of circumstances, including the following scenarios:

- A major storm event leading to significant damage to Alectra Utilities' plant, requiring the utility to replace the assets to restore power back to the customers.
- Distribution equipment (such as a pole, switchgear, or transformer) fails during operation and requires replacement to restore power.
- A vehicle hits distribution equipment, damages the equipment and requires replacement to restore power or to maintain safety.
- During routine inspection or maintenance, an Alectra Utilities' crew identifies a transformer which has a significant leak, compromised structural integrity, or is on the verge of failure. All of these pose a safety risk to employees or the public. That transformer would be replaced and any clean up or site restoration will be completed as a reactive project.

By their nature, specific reactive capital investments are unplanned and unpredictable. Although Alectra Utilities can be confident that significant reactive expenditures will be required each year, it is impossible to identify the specific work that may be required in future years. Accordingly, the forecast expenditures for this portfolio are based on historic reactive capital spending across Alectra Utilities' operational areas.

Alectra Utilities has taken a conservative approach to forecasting the level of reactive expenditures likely to be required during the DSP period. Even with the increased System Renewal investments planned for the 2020-2024 period, the utility expects that distribution equipment will fail at increasing rates due to the backlog of deteriorated assets and the increasing frequency and intensity of extreme weather events.[89] As shown in Table A06 - 1, Alectra Utilities spent approximately $20.5MM on reactive capital work in 2018. It has not budgeted to reach that

[89] Asset condition and weather-related trends are discussed in DSP Section 5.2.3 and 5.3.2, respectively.

level until 2022. In the first two months of 2019, Alectra Utilities has overspent in comparison to historical five year average for the month of January and February.

Table A06 - 1: Investment Subgroup Summary

	Historical Expenditure				Bridge	Forecasted Expenditure				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$16.7	$14.6	$15.6	$20.5	$17.2	$18.8	$19.2	$19.6	$20.0	$20.4
Primary Driver:	Failure									
Secondary Drivers:	Reliability, Safety									
Outcomes:	Reliability, Customer Value, Safety									

II Investment Description

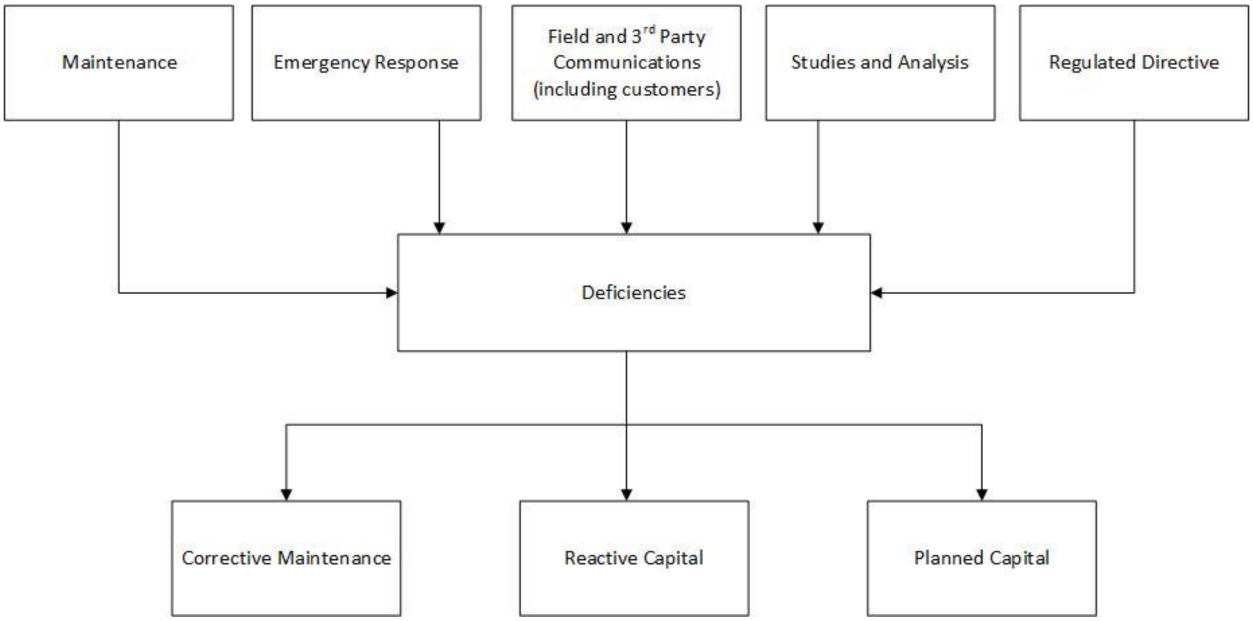
The Reactive Capital investment portfolio consists of work that must be done on an urgent basis to repair or replace equipment that has either failed, will fail imminently, or poses an imminent safety risk. The work conducted under the Reactive Capital portfolio is non-discretionary, as it is necessary to supply electricity to customers and to maintain the safety of the distribution system.

Any major distribution asset may need to be replaced on a reactive basis. The specific assets that will be replaced during this DSP period will naturally depend on the specific assets that either fail, are damaged, or identified as posing an imminent safety or failure risk. Figure A06 - 1 sets out examples of assets that failed catastrophically, requiring reactive work to restore power and make sites safe for the public and Alectra Utilities' crews. In some cases, a reactive solution may be sufficient to address a failed asset. However, in some cases a reactive project may be a temporary measure to restore power until a planned project can be executed to address an underlying issue.

Figure A06 - 1: Catastrophic Failure of Switchgear and Vault Transformer

Alectra Utilities identifies assets for reactive replacement through several channels. They are represented in Figure A06 - 2.

Figure A06 - 2: Deficiencies Flow Process



Assets may be replaced on a reactive basis, if a field inspection identifies that an asset needs to be replaced immediately. This is called an "inspection-based intervention." Assets may require immediate intervention for a range of factors, but will primarily be identified for replacement due to advanced deterioration or because they pose a safety risk to public or crews. Alectra Utilities must address these risks quickly, and cannot delay addressing failed or high-risk assets until a planned project is completed.

Assets may also need to be replaced reactively when they are damaged due to extreme weather events, accidents, or vandalism. If these events leave equipment in a state where failure is imminent or pose a safety risk.

Figure A06 - 3: Failure of Overhead Distribution System due to Storm

When an asset needs to be replaced reactively, the first priority is restoring power to affected customers and addressing any immediate safety risks. As a result, equipment is typically replaced like-for-like with no major reconfiguration. The equipment replaced may conform to current Alectra Utilities standards and specifications. For example, if a padmounted transformer fails, it will be replaced with a padmounted transformer that conforms to current standards and specifications, including switches and fault indicating equipment. Similarly, if an overhead pole-top transformer fails, it will be replaced with a pole-top transformer that satisfies current standards, along with an animal guard.

2.1 Summary of Investment Outcomes and Benefits

Table A06 - 2 summarizes the outcomes and benefits associated with the Reactive Capital investment.

Table A06 - 2: Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Customer Value	As this initiative will allow for assets to be identified as being at end-of-life as part of the inspection procedure, there is the opportunity to replace the asset proactively without having to incur an outage and disrupt the customers.
Reliability	Limit service interruptions and contribute to system reliability by replacing equipment that has failed or with a high risk of failure.
Safety	These projects are intended to primarily address failed assets; however; investments required to address immediate safety issues, including issues presenting a potential risk to public safety identified by the Electrical Safety Authority, are included in this project.

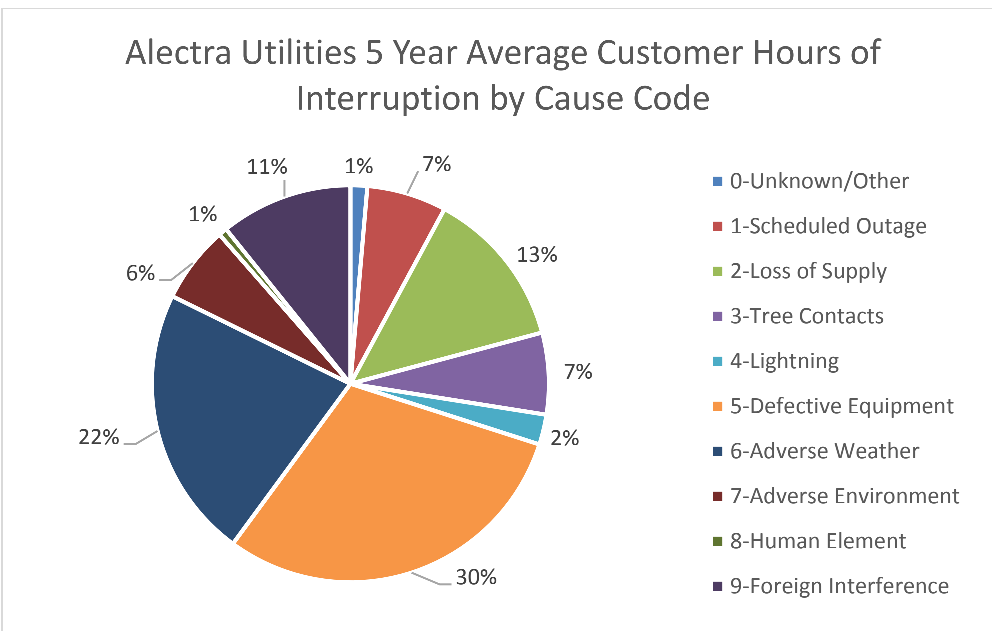
III Investment Drivers and Need

3.1 Purpose

Alectra Utilities maintains a discrete budget for reactive capital expenditures. This allows the utility to respond to some level of asset failures without drawing resources away from other important, planned capital projects. Without this budget, Alectra Utilities would continually be required to re-prioritize necessary renewal investments to accommodate urgent reactive work.

Distribution equipment fails for many reasons, ranging from defective equipment, to adverse weather, to interference from humans or animals. Figure A06 - 4 sets out the causes of customer minutes of interruption in the period from 2014 to 2018. Over half of customer hours of interruption in this period were caused by defective equipment and adverse weather.

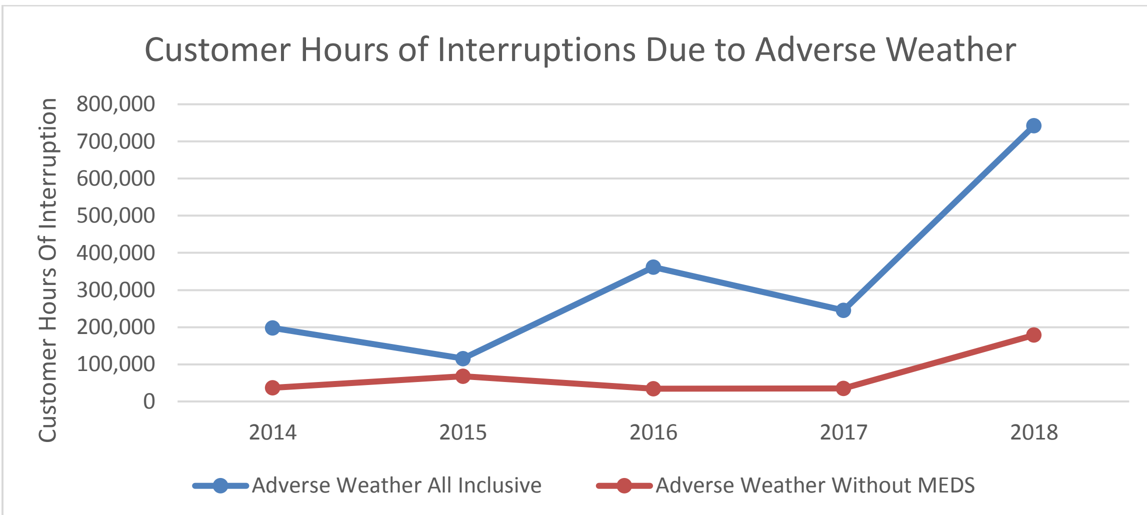
Figure A06 - 4: Alectra Utilities 5 Year Average Customer Hours of Interruption by Cause Code (2014 – 2018)



As described further below and in section 5.2.3 of the DSP, Alectra Utilities' assets are currently deteriorating at a higher rate than the utility has been able to replace them with available funds. Although Alectra Utilities plans to increase system renewal spending on the categories of assets that are responsible for the majority of outages, nonetheless it expects that significant reactive expenditures will be required to maintain reliability due to failing equipment.

Adverse weather conditions have also had an increasing impact on Alectra Utilities' distribution system and the reliability of its service. As set out in Figure A06 - 5 below and as described in section 5.3.2 of the DSP, adverse weather has increasingly been responsible for interrupted service to Alectra Utilities' customers.

Figure A06 - 5: Customer Hours of Interruptions Due to Adverse Weather (2014-2018) with and without MEDs



While planned work is necessary to address these negative reliability trends, the work done under the Reactive Capital portfolio is also required to restore power when an asset fails.

The primary and secondary drivers are further defined and summarized in Table A06 - 3.

Table A06 - 3: Investment Drivers

Investment Driver	Reasoning and Investment Benefits
Primary Driver: Failure	Reactive Capital investments are primarily driven by asset failure, in that the expenditures under this portfolio either relate to assets that have failed, or are at imminent risk of failure.
Secondary Driver: Safety	Reactive Capital investments address failed assets or those at risk of failing or causing a safety risk. Failing and failed assets may pose significant public and crew safety. Assets that have been identified as posing an imminent safety risk necessarily entail a safety risk that Alectra Utilities must address.
Secondary Driver: Reliability	Reactive Capital investments are necessary to restore power to customers when assets fail.

IV Investment Timing and Pacing

4.1 Summary of Expenditures

Table A06 - 4 provides the year-over-year breakdown of Alectra Utilities' Reactive Capital investments, including the historical period from 2015-2018, the 2019 bridge year, and the DSP period from 2020-2024.

Table A06 - 4: Historical and Forecast Investment Spending

	Historical Expenditure				Bridge	Forecast Expenditure				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$16.7	$14.6	$15.6	$20.5	$17.2	$18.8	$19.2	$19.6	$20.0	$20.4

4.2 Historical Expenditures (2014-2019)

Between 2015 and 2019, Alectra Utilities spent a total of $84.6MM on reactive capital investment. The utility's annual expenditures varied year-over-year, depending on the specific asset failures and identified high-risk assets in each year.

The overall trend has been toward increasing need for reactive investments in Alectra Utilities' distribution system. As discussed above, the upward trend in the utility's reactive capital costs is due primarily to the increasing proportion of its assets that are in poor or very poor condition, as well as the increase in both the frequency and intensity of extreme weather events.

4.3 Future Expenditures (2020-2024)

During the DSP period, Alectra has budgeted $98.0MM for Reactive Capital expenditures. The budgeted expenditures are based on historical volumes and cost of work. The budgeted cost of reactive investments in 2020 is based on a 2 year average (2018-2019) with no inflation factor. From 2020 to 2024, Alectra Utilities has budgeted a year-over-year inflationary increase of approximately 2%.

While Alectra Utilities plans to invest to address the high level of deteriorated and aging assets in its system, and to harden the system for more frequent and intense weather events, it expects that both trends will continue beyond the DSP period.

As noted in section 1 above, Alectra Utilities believes that its forecast is conservative. The utility's forecast expenditures are below 2018 levels until 2022, and actual expenditures in 2019 are already likely to exceed the budgeted amount. In the first two months of 2019, Alectra Utilities has overspent in comparison to historical five year average for the month of January and February.

4.4 Investment Pacing and Prioritization

By its nature, expenditures made under the Reactive Capital portfolio are unpredictable. It is not possible to pace or prioritize reactive work, as it is driven by assets that have failed or unexpectedly require immediate replacement. Although high-risk assets identified through inspections have not failed yet, they are always high-priority, due to the high potential for reliability and safety issues.

4.5 Execution Approach

Alectra Utilities will leverage internal and external contractors to complete the replacement of these assets under the Reactive Capital program, either following the outage event under emergency conditions, or proactively as an inspection-based intervention.

The Execution phase will follow Alectra Utilities' internal project management and work order management which provides specific guidelines, procedures, work instructions, and industry best practices that allow the project work to be performed in an economically efficient, cost effective, and safe manner.

V Options Analysis

Alectra Utilities has considered the following two intervention options with respect to reactive capital:

- Do Nothing – do not replace asset following failure
- Replacement of the asset – either reactively following failure, or proactively as inspection-based intervention.

Do Nothing

In this case, the Status Quo option would in effect mean that the utility would do nothing once the asset has failed and allow the outage to be maintained. This is not a viable option, as to leave customers without power is in direct contravention to the Distribution System Code - Section 4.4.

Replacement of the asset

Under this option Alectra Utilities would continue with the status quo and replace asset reactively as required. Per Figure A06 - 2 Alectra Utilities uses Corrective Maintenance and Planned Capital as options where possible, as alternatives to a reactive replacement.

VI Investment Projects

The material investments from 2020 to 2024 that form the Reactive Capital investments are included in Table A06 - 5.

Table A06 - 5: Material Business Cases

Project Code	Project Name	CAPEX ($MM)
101824	Reactive Capital	$98.0

Appendix A07 - Rear Lot Conversion

I Overview

The rear lot conversion initiative is designed to renew rear lot overhead infrastructure that is aged and functionally obsolete. These assets pose a safety risk for the public and for Alectra Utilities crews, are more prone to failure than other overhead distribution assets, and otherwise do not align with current standards, policies and practices.

Alectra Utilities' service area contains multiple neighbourhoods with rear lot infrastructure, which supplies approximately 11,000 customers in the East and West operating zones. In general, this infrastructure was installed in older neighbourhoods, with assets that are now at least 40 years old. In many cases conductors run through customers' back yards, adjacent to swimming pools, and other spaces that are both hard to access for Alectra Utilities' crews, and are unacceptably close to the members of the public.

Figure A07 - 1: Tree-house Close to Pole and Energized Conductor

Due to their location, rear lot overhead assets are situated near adjacent properties and vegetation. For these reasons, rear lot infrastructure generally poses a higher risk of failure and elevated safety risks to the general public should the assets fail.

The continued operation of these assets is further complicated by their location in customers' backyards, therefore inhibiting Alectra Utilities' ability to carry out day-to-day operational procedures, such as visual inspection and maintenance activities. As the assets age and as their condition deteriorates, the impact of these accessibility issues is magnified, further affecting the reliability of customers' service.

For example, during the December 2013 ice storm, customers with rear-lot service were disproportionately affected. Because of the locations of these customers' connections, many were struck by falling trees and branches. The limited accessibility of these locations restricted crews' ability to restore power for these customers, resulting in longer power outages. For example, in Alectra Utilities' Eastern Operational Area, customers with rear-lot connections experienced total customer minutes interrupted (CMI) of 29,831,573. These minutes of interrupted service accounted for 17% of the total system CMI during the ice storm event, despite the fact that these customers only accounted for 0.01% of total customer count.

Rear lot infrastructure is functionally obsolete for the following key reasons:

- The rear lot configuration is generally unsafe to the public due to the large trees growing near energized power lines. In tandem with such an unsafe configuration, there are also line clearing hazards and related additional costs to do this work.
- Alectra Utilities is unable to use labour saving tools and devices such as bucket trucks to efficiently maintain and repair the distribution system due to assets located in customer backyards.
- Rear lot wood poles are generally congested, due to multiple service attachments and communication drops, which generally make it impossible to sufficiently climb poles. Crews must, therefore, use ladders to access these poles.
- Alectra Utilities is limited in utilizing ladders to access the overhead system due to Ministry of Labour restrictions for congested areas.
- Due to the presence of legacy porcelain top tie insulators, rear lot lines must be fully isolated before any maintenance or repair work on the overhead system can commence.

- Porcelain insulators are far more susceptible to contamination and flashover when compared to present-day standard polymer insulators.
- Rear lot infrastructure typically contains undersized #4 aluminum conductor steel-reinforced cable and aluminum conductor, along with #4 and #6 copper conductor, which are undersized and generally have a greater probability of annealing due to their reduced carrying capacity. These conductors must be fully isolated before any work can commence.

In 2014, the legacy PowerStream retained CIMA (Refer to EB-2015-0003), a consulting firm, to review the PowerStream distribution system's capability to withstand severe ice storm. According to CIMA's findings, a key recommendation was to convert the rear lot overhead supply system to a front lot underground supply system. The latter configuration would permit Alectra Utilities to apply standard maintenance and operational practices by eliminating the accessibility issues associated with the legacy rear lot infrastructure. Furthermore, the present day standard underground solution would provide significant system resilience benefits as the new underground assets minimize risks of external elements, including weather-related, animal-related and human-related contacts.

During the DSP period, Alectra Utilities plans to continue converting rear lot infrastructure to standardized front-lot underground infrastructure.

Table A07 - 1 summarizes the total investments and drivers and outcomes for the rear lot conversion projects.

Table A07 - 1: Investment Subgroup Drivers and Outcomes Summary

	Historical Expenditure				Bridge	ForecasteExpenditure				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$4.0	$4.6	$3.4	$0.0	$5.1	$4.8	$1.2	$1.2	$4.2	$8.5
Primary Driver:	Functional Obsolescence									
Secondary Drivers:	Reliability, Safety									
Outcomes:	Customer Value, Reliability, Safety, Environment, Efficiency									

II Investment Description

2.1 Conversion of Rear-Lot Infrastructure to Front-Lot Underground Design

This program involves the conversion of the legacy rear lot overhead system to current-standard front-lot underground infrastructure, including the installation of padmounted transformers, tree-retardant cross-linked polyethylene ("TRXLPE") underground cables in conduit and solid dielectric padmounted underground switches. All primary voltage assets will be converted accordingly to underground infrastructure. Similarly, all secondary voltage assets will also be converted such that customer meter bases will be supplied via underground connections.

The front-lot configuration introduces a number of benefits with respect to reliability and safety, while mitigating the asset failure risk and operational constraints.

More specifically, the proposed conversion will improve reliability as underground assets are protected from external impacts (i.e., resulting from contacts with adjacent vegetation, or animal or human contacts). Alectra Utilities' field crews will be able to access front lot infrastructure more easily, which will reduce outage restoration time. The elimination of rear lot assets will also mitigate a range of safety risks, such as the elimination of manual procedures, such as the usage of ladders when attempting to repair or replace the rear lot overhead infrastructure, as standardized equipment such as bucket trucks cannot be used to access this infrastructure.

Other forms of assets that may present safety-related risks will be replaced through these investments. As an example, porcelain insulators, which possess an elevated probability of contamination and flashover will be replaced with standardized polymeric insulators. Smaller diameter conductors, such as #4 aluminum conductor steel-reinforced cable and aluminum conductor, along with #4 and #6 copper conductors will be replaced with standardized conductor sizes. As discussed in Section 3.1.2 bellow, these conductors have an elevated probability of failure, which can result in downed wires, which can present serious safety risks to the public. Removing these assets will significantly improve public safety.

The renewed assets will meet current standards to ensure minimum clearance requirements of 3 metres to the public and 0.9 metres to authorized workers as defined by Infrastructure Health and Safety Association, Electrical Utility Safety Rule 129, which outlines the safe limits of approach to maintain a safe working environment. The renewed front-lot assets align to current standards, meaning that they can be fully accessed from the front of the customer property using standard Alectra Utilities vehicles and equipment. The front lot design eliminates potential operational constraints, as the new assets will be installed within applicable easement areas and fully accessible in accordance with Alectra Utilities' standard maintenance and visual inspection procedures. In general, converting to an underground front lot supply also enhances reliability, as external events, such as animal contacts, tree contacts and other external factors that can compromise overhead plant will have no impact on underground infrastructure. The elimination of the rear lot will also lead to the elimination of tree trimming activities at these locations.

Alectra Utilities plans to install underground padmounted transformers that are fully switchable, enabling efficient isolation, sectionalisation and restoration procedures which can be performed should an outage occur. Furthermore, additional fault locators will be installed for each transformer, switch and wood pole, to further improve fault locating capabilities for crews.

2.2 Summary of Investment Outcomes and Benefits

Table A07 - 2 summarizes the outcomes and benefits associated with Rear Lot Conversion investments.

Table A07 - 2: Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Customer Value	• Increases customer satisfaction by eliminating the requirement to access private customer property to perform maintenance and inspection. • Eliminates overhead electrical plant directly, within their private property and renews the distribution system to present day standards. Removal of overhead electrical plant eliminates risks of customer safety and risk of property damage should the overhead system fail.
Reliability	• Improves reliability as degrading and ageing rear lot assets will be replaced with new infrastructure built to present-day standards. • The addition of underground padmounted switches and switchable transformers will also introduce additional reliability benefits through enhanced sectionalizing and restoration procedures that can be performed. • Reliability issues stemming from external events (e.g., human, animal and tree contacts) are mitigated with underground infrastructure. • Front lot equipment can be efficiently accessed in a reduced amount of time when compared to the existing rear lot assets, which inhibit and restrict crew accessibility and therefore take significantly longer to perform restoration procedures. The system average interruption duration index over the last three

Outcome	Investment Benefits and Objectives
	years for rear-lot supply customers was 4.8-time worse compared to the overall system average interruption duration.
Safety	• Present-day underground front-lot infrastructure is better aligned with current work practices, permit efficient access to infrastructure and utilization of labour saving devices such as a bucket truck. In comparison, overhead rear-lot infrastructure requires the use of ladders to access transformer, switch and conductor assets and generally requires manual replacement of equipment without the use of labour saving tools and devices.
Environment	• For areas where voltage conversion is completed concurrently with the rear-lot renewal, the investment will reduces line losses. • The risk of an oil spill due to degrading overhead rear-lot transformers is mitigated through rear lot conversion as transformers will be renewed to pad mounted units.
Efficiency	• Permits operational improvements (e.g. enhanced switching and sectionalizing within underground loops, visible breaks within the underground padmounted switches, as well as enhanced fault indicating devices installed at transformers, switches and wood poles); • Eliminates line losses associated with non-standard rear lot voltages; • Reduces inventory associated with lower voltage class assets.

III Investment Drivers and Need

3.1 Purpose

Table A07 - 3 below defines and summarizes the primary and secondary drivers for Overhead Legacy Infrastructure.

Table A07 - 3: Investment Drivers

Investment Driver	Reasoning and Investment Benefits
Primary Driver: Functional Obsolescence	The primary driver for these investments is functional obsolescence. Overhead legacy assets, including legacy rear-lot construction and legacy under-classed poles, conveying four feeder circuits, no longer align with Alectra Utilities' standards and practices. Rear lot infrastructure introduces accessibility and safety issues. These assets cannot be maintained using efficient maintenance and operational practices the leverage labour saving equipment and devise such as bucket trucks.
Secondary Driver: Safety	Rear lot infrastructure poses an elevated safety risk to (i) field crews, due to the non-standard and manual procedures that must be utilized to maintain and operate this infrastructure on a regular basis, and (ii) the general public, due to the limited clearances between the electrical plant and customer properties.
Secondary Driver: Reliability	Given that like-for-like replacement would perpetuate some of the inherent shortcomings associated with rear lot supply, the proposed rear lot conversion investment will involve renewal to present-day standards which provides reliability benefits including an expected 11-fold improvement to rear-lot SAIFI and more than a 3-fold improvement to rear-lot SAIDI when compared the three-year historical system SAIFI and SAIDI.

3.1.1 Accessibility Issues

Rear lot infrastructure currently supplies approximately 11,000 customers within Alectra Utilities' service area, mainly in Alectra Utilities' Eastern Operational Area (York Region, Simcoe County), and the Western Operational Area (Hamilton, St. Catharines). Given that these rear-lot assets have an average age of 43 years or older, they pose an elevated risk of failure. As the infrastructure continues to age and deteriorates over time, it becomes increasingly more difficult for Alectra Utilities to monitor asset deterioration due to accessibility challenges. As discussed below, to ensure system reliability as well as employee and public safety, it is necessary to replace the existing rear lot infrastructure across Alectra Utilities' service area.

Rear lot infrastructure is predominantly installed on customers' private property, typically in customer backyards. As a result, the infrastructure creates access constraints required to carry out maintenance and visual inspections. Figure A07 - 2 shows one shows a typical rear lot location where the poles are inaccessible due to vegetation growth.

Figure A07 - 2: Inaccessible Pole in Poor Condition (cracked and rotten)

For example, standardized bucket trucks are unable to access this plant, due to its location within the backyards of customer property. Due to the lack of access, all maintenance and inspection work concerning these assets must be performed manually. Crews must climb poles, or use ladders to sufficiently access the assets and hardware at the top of the lines. There are Ministry of Labour restrictions on how ladders can be utilized within Alectra Utilities' system, which further complicates their use on rear lot infrastructure.

When Alectra Utilities maintains standard overhead infrastructure, many maintenance and inspection activities can be performed without the need of isolating the line (i.e. working live on energized equipment), meaning that customers do not have to experience an outage. However, when maintaining rear lot infrastructure, the line must be isolated prior to climbing the pole or working on the secondary bus, due to the presence of porcelain top tie insulators. Porcelain insulators, in general, are far more susceptible to contamination when compared to standardized polymeric insulators, and therefore these legacy porcelain insulators have a far greater susceptibility to flashover events, which can result in pole fires, thus introducing safety-related risks to the general public.

3.1.2 Safety Issues

Rear lot construction poses serious safety risks to both Alectra Utilities field crews as well as the general public. Due to the nature of the rear lot construction and its close proximity to customer property, the rear lot lines often do not comply with the minimum clearance requirements as defined by Electrical Utilities Safety Association of Ontario (EUSA) Rule 129. These assets are also often within close proximity of residential pools, which further heightens the potential electrical hazards.

Figure A07 - 3: Secondary Distribution Conductor Attached to a Tree

Figure A07 - 1 to Figure A07 - 3 highlight some of the safety concerns with customer equipment being close to the energized lines as well as non-standard construction which does not meet the clearance requirement. As described in Section 3.1.1, field crews are unable to execute standardized operating practices when maintaining, inspecting, or replacing these assets.

Rear lot infrastructure often contains undersized #4 aluminium conductor steel-reinforced cable and aluminum conductor, along with #4 and #6 copper conductor, which are undersized and generally have a greater probability of annealing due to their reduced carrying capacity. In a catastrophic failure event, the resulting downed lines can introduce extremely serious safety risks to the public, as these downed lines would occur directly within the backyards of customer property. The rear lot configuration is generally more hazardous to the public due to the large trees growing near energized power lines. This risk is compounded by line-clearing hazards and related additional costs to do this work.

Existing rear lot infrastructure also falls under the minimum clearance requirements of 3 metres to the public and 0.9 metres to authorized workers as defined by EUSA Rule 129, which outlines the safe limits of approach in order to maintain a safe working environment.

3.3 Reliability Performance

Typically, overhead infrastructure poses an elevated risk of reliability impacts due to external factors, such as tree contacts, animal contacts, and human contacts. Specifically, rear lot infrastructure poses an even higher risk than typical overhead assets, due to their non-standard installation in the backyards of customers' private properties. These assets are typically installed under tighter clearances about trees and other vegetation, thereby creating an elevated risk of tree, animal and human-related contacts. When power is interrupted, it takes more time for crews to respond, since they must first gain access to the affected property. In addition, the limited clearance poses challenges for bucket trucks and other vehicles that must gain access to the impacted plant to carry out repair work.

Table A07 - 4 provides a breakdown of the average SAIFI and SAIDI values for the rear lot systems to be addressed as part of this investment. Customers located within these proposed locations are predominantly residential, with some commercial customers.

The average 3-year system-wide SAIFI is 1.44 interruptions, the average 3-year rear-lot service SAIFI is 12.8 interruptions for the areas selected, which represents a 9-fold difference between the two systems. Much of this difference in frequency of outages is due to the increased probability of tree and animal contacts due to the location of this infrastructure within the backyards of customer property as well as the proximity between these lines and adjacent trees and plant life. Conversely, the system-wide SAIDI is 1.43 hours, while rear-lot service SAIDI is 4.33 hours, which represents a 3-fold increase. This high SAIDI reliability index for rear lot is largely due to the operational constraints of access and requirement to complete the repair or replacement utilizing without labour saving equipment or devices such as bucket trucks.

Table A07 - 4: Average SAIFI/SAIDI Statistics (2015-2017) for Proposed Project Areas

Project		Year	Average SAIDI (min) 2015-2017	Average SAIFI 2015-2017
150399	Rear Lot Conversion - Richlieu Dr and Trelawne Dr	2023-2024	87	40
150044	Rear Lot Supply Remediation - Blake/Kempenfelt	2020	132	0.66
150043	Rear Lot Supply Remediation - East of Queen St. to Eastern Ave./North of Greenway St.	2020	582	1.7
150047	Rear Lot Supply Remediation - Royal Orchard – North	2020-2022	243.60	3.21
150378	Rear Lot - East of Queen Street/North of Mill Street	2023	516	1
150330	Rear Lot Conversion – Marsdale	2023-2027	67.4	19.2
150380	Rear Lot - Gunn/Oakley Park/St.Vincent	2024	780	1
150329	Rear Lot Supply Remediation - Main Street / Unionville / Carlton	2024-2026	100.8	0.50
150397	Rear Lot Conversion - Riverview Blvd and Northcliffe	2024	70.1	16.9
150398	Rear Lot Conversion - Strathcona Dr	2024	21	44
			260	12.82

The reliability issues with rear lot distribution are magnified during major storm events. In the December 2013 ice storm, trees and branches fell onto power lines and created prolonged power outages to customers. Due to the aforementioned issue of proximity between trees and rear lot plant, the prolonged power outages in rear lot locations were far more pronounced relative to front-lot installations, with rear lot locations accounting for 16.68% of the total CMI during the ice storm event. This particular event resulted in a total CMI for rear lot locations of 29,831,573 in Alectra Utilities' Eastern Operational Area.

IV Investment Timing and Pacing

4.1 Summary of Expenditures

Table A07 - 5 provides the year-over-year breakdown of Rear Lot Conversion investments, including the historical period from 2015-2018, the bridge year in 2019, and the DSP period from 2020 to 2024.

Table A07 - 5: Historical and Proposed Investment Spending

	Historical Expenditure				Bridge	Forecast Expenditure				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$4.0	$4.6	$3.4	$0.0	$5.1	$4.8	$1.2	$1.2	$4.2	$8.5

4.2 Historical Expenditures (2015-2019)

Historical expenditures between 2015 and 2019 total $17.1 MM. There were no expenditures in 2018 as rear lot projects were dropped to due to mandatory work related to requests from road authorities. There are four projects which will be completed in 2019 at a cost of $5.1 MM.

4.3 Future Expenditures (2020-2024)

Future expenditures from 2020 to 2024 will total $19.9 MM. These expenditures will serve to eliminate the oldest (i.e. assets older than 40 years of age) rear lot infrastructure with new standardized underground front-lot infrastructure. As described in section 5.4.1 of the DSP, Alectra Utilities' capital investment optimization process evaluates and paces projects based on values and risk over the utility's entire capital portfolio. This process resulted in reduced Rear Lot Conversion work in 2021 and 2022. The projects that would otherwise have been executed in those years are planned for 2023 and 2024.

Each year, a number of rear lot locations are prioritized for conversion to the standardized front-lot underground infrastructure, in order to address the known operational constraints and to maintain reliability and customer service. Key factors used to identify the projects include the following:

- Asset Age
- Asset Condition

- Imminent Health, Safety and Environmental Issues
- System Configuration and Capacity
- Impact to Reliability
- Criticality of the Circuit
- Economic and Cost Benefit Analysis
- Co-ordination with other Capital and Maintenance Work Programs

4.4 Execution Approach

Alectra Utilities will leverage internal and external contractors to complete the design and construction of the new underground front-lot infrastructure. Alectra Utilities has retained external contractors working at different work sites throughout the year under a multi-year engineering procurement construction Master Service Agreement.

Rear lot projects are large projects and require extensive coordination efforts between Engineering, design, third parties and customers. The rear lot involves multiple interaction with the customers at it involves removal of the Alectra Utilities' plant, removal of the service mast or meter socket, locating a new underground equipment in front of house, restoration of customer's property after project completion. After the project is approved by Alectra Utilities the project is implemented in a coordinated fashion to minimize surprises and disruptions to the neighbourhood.

The following steps are undertaken on rear lot projects:

- Alectra Utilities communicates with the local municipality and other joint utilities to identify synergies in case they have plan to upgrading infrastructure in these older neighbourhoods (e.g. street lighting, cable/lighting or conduits for future projects such as water sewers).
- Alectra Utilities sends a letter to home owner with sketches of work to be performed on the property.
- Alectra Utilities sends follow-up letters regarding excavation, sod watering.

Regular progress meetings are held between Alectra Utilities and contractors to ensure technical and operational issues are resolved promptly.

The work itself is executed based on Alectra Utilities' project management methodology which provides specific guidelines, procedures, and work instructions based on industry best practices that allow the work to be performed in an efficient, cost-effective, and safe manner.

V Options Analysis

Alectra Utilities has considered the following possible options in order to proactively manage existing rear lot infrastructure:

- Status Quo / "Do Nothing"
- Replace existing Rear Lot Infrastructure with Rear Lot Overhead Infrastructure
- Replace existing Rear Lot Infrastructure with Partial Underground Infrastructure.
- Replace existing Rear Lot Infrastructure with Full Underground Infrastructure

5.1 Status Quo / "Do Nothing"

Under this option, no proactive investments would be executed to replace either existing rear lot infrastructure and these assets would only be intervened upon in reactive scenarios, when the assets have reached their end-of-life.

Under this approach, customers would be exposed to prolonged reliability impacts, due to the accessibility issues associated with rear lot infrastructure, as well as the complex restoration procedures that would be required for a four-feeder outage event.

As standardized equipment (e.g. bucket trucks) cannot be used to service rear lot plant, wood poles, transformers and overhead switches would have to be replaced manually, with field crews accessing private customer properties in order to execute the work. Customers and field crews would continue to be exposed to elevated safety risks, due to the minimal proximity between customer plant and the rear lot overhead lines, as well as the non-standard and non-ergonomic work procedures that field crews would have to continue to execute to sufficiently maintain, inspect and service the plant.

Finally, as assets are replaced reactively, new assets would need to be installed according to the rear lot configuration. By its design, rear lot can only be converted if the entire line is replaced at once as part of an overall project. Therefore, the legacy design will continue to be maintained under this scenario. This will include the continued operation of the legacy voltage system, along with continuing the associated inefficiencies, such as line losses.

Alectra Utilities rejected this approach due to inherent issues with maintenance, reliability, safety concerns and resulting operational inefficiencies.

5.2 Replace with Rear Lot Overhead Infrastructure

Under this option, existing rear lot infrastructure would be proactively replaced with new rear lot infrastructure that would remain within the customers' private property. As per this investment scenario, legacy voltage classes would be converted to the standardized voltage in the area. In addition, the existing infrastructure would be reconfigured in such a manner in order to make certain asset components more accessible from the street, such that standardized bucket trucks may access the plant during an outage event.

In most cases this approach would not be possible due to location of the assets, the need to access other private property, lack of easements, and other factors.

In addition, and critically, this approach would not address the inherent safety issues concerning rear lot distribution. Ultimately, the like-for-like renewal of these assets (i.e. same system configuration and same distribution voltage) will perpetuate the existing operating constraints and safety concerns. For these reasons, Alectra Utilities rejected this approach.

5.3 Replace with Partial Underground Infrastructure

This scenario involves the replacement of existing rear lot infrastructure with a new hybrid solution, where primary voltage infrastructure, including transformers, switches and lines would be installed as per an underground configuration within the front right-of-way, following standard Alectra Utilities installation practices. Under this approach, secondary infrastructure, including wood poles and secondary conductor, would remain in the rear lot in overhead configuration.

This approach would not fully address the reliability and safety concerns associated with rear lot distribution, as secondary connections will remain in the rear lot. However, future outage impacts will be reduced and contained to only those customers connected to the associated transformer. Lower voltage classes will also be converted up to the standardized 27.6kV voltage standard as per this investment option.

Under this option, reliability and safety issues would continue to persist due some infrastructure remaining overhead. The cost of partial underground renewal is higher than the renewal of the rear lot overhead and further more does not result in mitigating the risks associated with the existing system. This partial underground approach has been adopted where feasible.

5.4 Replace with Full Underground Infrastructure

This investment scenario considers the full replacement of existing rear lot infrastructure – including primary and secondary plant – with new front lot underground infrastructure. All existing primary and secondary distribution assets within the rear lot corridor will be removed and replaced with new underground primary and secondary infrastructure that is installed within the front lot corridor as per current standard design practices. Underground secondary cables will run from the front lot underground transformers to the individual meter bases in order to supply the customers.

This approach would completely mitigate the reliability and safety issues associated with rear lot distribution, as well as the operational constraints associated with the existing infrastructure. This approach also introduces efficiencies for the utility, as tree trimming activities can be eliminated and line losses associated with the legacy voltage classes can be eliminated. For these reasons, this is Alectra Utilities preferred approach.

VI Investment Projects

The material investments from 2020 to 2024 that form the Rear Lot investments are included in Table A07 - 6.

Table A07 - 6: Material Projects and Initiatives

Project Code	Project Name	CAPEX ($MM)
150047	Rear Lot Renewal Project - Royal Orchard - North	$4.0
150330	Rear Lot Renewal Project - Marsdale	$3.1
150043	Rear Lot Supply Remediation - East of Queen St. to Eastern Ave./North of Greenway St.	$2.6
150329	Rear Lot Renewal Project - Main Street / Unionville / Carlton	$2.5
150399	Rear Lot Renewal Project - Richlieu Dr and Trelawne Dr, St.Catharines	$2.4
150380	Rear Lot Supply Remediation - Gunn/Oakley Park/St.Vincent	$1.8
150378	Rear Lot Supply Remediation - East of Queen Street/North of Mill Street	$1.8

Appendix A08 - Substation Renewal

I Overview

Station infrastructure is critical to the transformation of high voltage supply from the transmission system to distribution voltage supply for utilization in Alectra Utilities' service territory. Alectra Utilities has 14 transformer stations (TS), which are supplied from the transmission grid at 115 kV or 230 kV, and 155 municipal substations (MS), which are supplied from the low-voltage side of TSs at 44 kV, 13.8 kV or 27.6 kV. Station asset failures can lead to service disruptions of up to several thousand customers for several hours. Through the Substation Renewal investment, Alectra Utilities proposes to replace aging and legacy substation assets (i.e., station power transformers, circuit breakers, and switchgear) with new standardized equipment in alignment with Alectra Utilities' current needs and requirements.

The primary driver of replacements under this investment is the need to mitigate failure risks that have been identified based on ongoing monitoring and inspections (including visual observations, equipment testing, dissolved gas analysis, oil quality testing and transformer load monitoring) as well as condition assessment results. In this regard, the results from Alectra Utilities' Asset Condition Assessment (ACA) models with respect to station assets were an important input for the investment planning process. The ACA generates Health Indices (HIs) for individual station components, providing a useful indicator of asset conditions across the utility's stations. HI values are scored from 0 to 100 and accordingly grouped into five bands: Very Poor, Poor, Fair, Good, and Very Good. Secondary drivers include functional obsolescence (i.e., legacy assets without manufacturer support or spare parts availability), safety hazards (e.g., risk of flashover due to outdated switchgear design) and environmental risks (e.g. transformer oil leaking into the water table).

On this basis, Alectra Utilities has identified and prioritized twelve substation renewal investments that form part of this investment:

1. Station Switchgear Replacement MS10 - replacing the 13.8 kV switchgear at MS10 in Brampton.
2. Station Switchgear Replacement Aquitaine MS59 LV1 - replacing the LV1 13.8 kV switchgear at Aquitaine MS59 in Mississauga.

3. Station Switchgear Replacement Battleford MS54 LV1 - replacing the LV1 13.8 kV switchgear at Battleford MS54 in Mississauga.
4. Station Switchgear Replacement Shawson MS43 LV1 - replacing the LV1 13.8 kV switchgear at Shawson MS43 in Mississauga.
5. Station Switchgear Replacement City Centre North MS47 HV1 - replacing the T1 transformer protection device, the HV1 switchgear, and associated breaker protection relays at City Centre North MS.
6. Station Switchgear Replacement City Centre North MS47 HV1 - replacing the T2 transformer protection device, the HV2 switchgear, and associated breaker protection relays at City Centre North MS.
7. Station Switchgear Replacement Bloor MS38 LV1 - replacing the LV1 13.8 kV switchgear at Bloor MS38 in Mississauga.
8. Station Switchgear Replacement City Centre South MS61 LV1 - replacing the LV1 13.8 kV switchgear at City Centre South MS61 in Mississauga.
9. MS Transformer and HV Switchgear Replacement Western MS36 T1 and HV1 - replacing the T1 transformer and HV1 switchgear at Western MS36 in Mississauga.
10. MS Transformer and HV Switchgear Replacement Munden MS35 T1 and HV1 - replacing the T1 transformer and HV1 switchgear at Munden MS35 in Mississauga.
11. Planned Circuit Breaker Replacement Markham TS#3 - E and Z Buses - replacing the eight GEC PBOX 36 27.6 kV feeder circuit breakers at Markham TS#3.
12. Station Switchgear Replacement Big Bay Point MS304 - replacing the 15 kV switchgear and primary circuit switcher at Big Bay Point MS304 in Barrie.

Table A08 - 1 below provides a summary of the historical and forecast spend, as well as primary and secondary drivers, and key outcomes. Historical expenditures were established based on legacy renewal processes. Under consolidated Alectra Utilities practice, investment portfolio optimization is performed using the Copperleaf C55 system, which provides an optimal capital portfolio that balances financial and resource driven constraints as well as investment benefits and risks in alignment with corporate strategic objectives. The 2020 to 2024 investment portfolio optimization resulted in lower funding allocated to station renewal investments in the forecast period vs. the historical period. The needs for station renewal investments were weighted against other investment needs in the investment portfolio, and were deemed to provide a lower value compared to other system investments, particularly underground primary cable system renewals. As a result a number of proposed station investments were deferred beyond the DSP planning period**.**

Table A08 - 1: Investment Subgroup Summary

	Historical Expenditure				Bridge	Forecasted Expenditure				
Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CAPEX ($MM)	$9.6	$10.6	$9.1	$10.4	$5.0	$12.8	$4.4	$2.8	$3.2	$5.5
Primary Driver:	Failure Risk									
Secondary Drivers:	Functional Obsolescence, Safety, Environmental Risk									
Outcomes:	Safety, Reliability, Efficiency, Customer Value, Environment									

II Investment Description

The majority of stations renewal investments in the DSP are to renew equipment at Alectra Utilities' MS facilities. The utility has assessed both TS and MS assets through the ACA process, and all TS power transformers were identified as being in very good condition. However, many MS assets (e.g., power transformers, switchgear and circuit breakers) were identified as requiring renewal. Depending on the substation asset, an asset failure can result in substantial customer outages. A failure at the feeder level can cause an outage for up to 2,000 customers. If an entire substation fails, up to 10,000 customers can be without power. The planned substation renewal investments are required to maintain ongoing electricity distribution service to all customers in a reliable, safe and cost-effective manner.

While failure risk associated with poor performance or condition deterioration represents the primary driver for renewal, Alectra Utilities uses an integrated lifecycle management strategy that also identifies renewal needs where station assets cease to meet operational requirements, are no longer supported by the manufacturer, or represent a material safety risk to the public or employees.

This investment includes the renewal of the following major substation asset classes:

- Station power transformers
- Station switchgear
- Station circuit breakers

This investment will target the renewal of municipal station power transformers, switchgear and circuit breakers at the following 12 substations:[90]

1. Station Switchgear Replacement MS10

This investment involves replacing the 13.8 kV switchgear at MS10 in Brampton with new switchgear having arc resistant construction and circuit breakers that meet Alectra Utilities' safety standard, and upgrading protection with new microprocessor relays. The existing switchgear line up is demonstrating signs of degradation in its housing and bus insulators are showing signs of

[90] Elements of the work are common to projects at multiple stations. For clarity, Alectra Utilities has repeated these descriptions for each project, as applicable~~.~~

corona and tracking. The manufacturer no longer supports this type of equipment and the design of the switchgear does not meet current safety standards and presents a potential safety risk to Alectra Utilities employees.

In addition, this station includes an ad hoc motorized feeder breaker control system that was custom built and installed in 1996 from salvaged parts. In order to test or maintain this unit, the entire bus must be taken out of service. As a result, this custom control system has received less maintenance over its lifetime and poses a reliability risk. Furthermore, MS10 is the only supply for a large commercial shopping complex. The impact of the loss of MS10 due to failure of the existing switchgear has a significant reliability impact on this customer. Alectra Utilities will address these risks through the planned replacement investment.

2. Station Switchgear Replacement Aquitaine MS59 LV1

This investment involves replacing the LV1 13.8 kV switchgear at Aquitaine MS59 in Mississauga with new switchgear having arc resistant construction and circuit breakers that meet Alectra Utilities' safety standard, upgrading protection with new microprocessor relays and replacing end-of-life feeder egress cables emanating from the feeder breaker positions in the new LV1 line up. The existing LV1 switchgear is not arc-proof and presents a safety risk to personnel. It houses 1983 Merlin Gerlin FLURAC FG2, SF_6 circuit breakers which are obsolete in that they are no longer supported by the manufacturer and parts are not readily available. Alectra Utilities has experienced breaker failure to operate events for this type of breaker due to design flaws associated with umbilical cord connectors, which resulted in loss of supply to the low side of a station and as such, requires replacement.

3. Station Switchgear Replacement Battleford MS54 LV1

This investment involves replacing the LV1 13.8 kV switchgear at Battleford MS54 in Mississauga with new switchgear having arc resistant construction and circuit breakers that meet Alectra Utilities' safety standard, upgrading protection with new microprocessor relays and replacing end-of-life feeder egress cables emanating from the feeder breaker positions in the new LV1 line up. The LV1 switchgear at is not arc-proof and presents a safety hazard to personnel. It houses 1983 Merlin Gerlin FLURAC FG2 SF_6 gas circuit breakers which are obsolete in that they are no longer supported by the manufacture and parts are not readily available. Alectra Utilities has experienced breaker failure to operate events for this type of breaker due to design flaws associated with umbilical cord connectors, which resulted in loss of supply to the low side of a station and as such, requires replacement.

4. Station Switchgear Replacement Shawson MS43 LV1

This investment involves replacing the LV1 13.8 kV switchgear at Shawson MS43 in Mississauga with new switchgear having arc resistant construction and circuit breakers that meet Alectra Utilities' safety standard, upgrading protection with new microprocessor relays and replacing end-of-life feeder egress cables emanating from the feeder breaker positions in the new LV1 line up. The LV1 switchgear at is not arc-proof and presents a safety hazard to personnel. It houses 1984 Merlin Gerlin F200 SF_6 gas circuit breakers which are obsolete in that they are no longer supported by the manufacture and parts are not readily available. Alectra Utilities has experienced breaker failure to operate events for this type of breaker due to design flaws associated with umbilical cord connectors, which resulted in loss of supply to the low side of a station and as such, requires replacement.

5. Station Switchgear Replacement City Centre North MS47 HV1

This investment involves replacing the T1 transformer protection device, the HV1 switchgear, and associated breaker protection relays at City Centre North MS. The current transformer protection device consists of vintage 1973 Markham Electric HPGE oil with spring actuator type 44 kV circuit breaker. Protection relays are 1973 GE products with no fault recording or modern communication capabilities. Further, the circuit breaker itself is problematic in that spare parts are no longer available and these units have a history of failure. A failure to this breaker would result in loss of supply from the station transformer, possibly for an extended period of time~~.~~

6. Station Switchgear Replacement City Centre North MS47 HV1

This investment involves replacing the T2 transformer protection device, the HV2 switchgear, and associated breaker protection relays at City Centre North MS. The current transformer protection device consists of vintage 1973 Markham Electric HPGE oil with spring actuator type 44 kV circuit breaker. Protection relays are 1973 GE products with no fault recording or modern communication capabilities. Further, the circuit breaker itself is problematic in that spare parts are no longer available and these units have a history of failure. A failure to this transformer would result in loss of supply from the station transformer, possibly for an extended period of time~~.~~

7. Station Switchgear Replacement Bloor MS38 LV1

This investment involves replacing the LV1 13.8 kV switchgear at Bloor MS38 in Mississauga with new switchgear having arc resistant construction and circuit breakers that meet Alectra Utilities' safety standard, upgrading to protection with new microprocessor relays and replacing end-of-life feeder egress cables emanating from the feeder breaker positions in the new LV1 line up. The LV1 switchgear at is not arc-proof and presents a safety hazard to personnel. It houses 1971 ITE 15HK magnetic air circuit breakers which are obsolete in that they are no longer supported by the manufacturer and parts are no longer readily available.

8. Station Switchgear Replacement City Centre South MS61 LV1

This investment involves replacing the LV1 13.8 kV switchgear at City Centre South MS61 in Mississauga with new switchgear having arc resistant construction and circuit breakers that meet Alectra Utilities' safety standard, upgrading to protection with new microprocessor relays and replacing end-of-life feeder egress cables emanating from the feeder breaker positions in the new LV1 line up. The LV1 switchgear includes 1986 Pioneer DST-2 magnetic air circuit breakers which are obsolete in that they are no longer supported by the manufacturer and parts are no longer readily available.

9. MS Transformer and HV Switchgear Replacement Western MS36 T1 and HV1

The investment involves replacing the T1 transformer and HV1 switchgear at Western MS36 in Mississauga with a new transformer and switchgear containing a circuit breaker and upgraded protections having new microprocessor relays. At the time of replacement, the age of the Pioneer 10 MVA, 27.6/4.16 kV transformer will be approaching end of life. Doble testing has indicated possible mechanical damage to the windings and the unit is also leaking oil and lacks modern spill containment. The HV1 switchgear includes obsolete electromechanical relays and obsolete S&C Electric All Duty fused disconnect, which failed in 2016 and now has alignment issues. The condition of transformer cables, foundation and spill containment will be verified as the replacement date approaches and repaired/replaced as required.

10. MS Transformer and HV Switchgear Replacement Munden MS35 T1 and HV1

The investment involves replacing the T1 transformer and HV1 switchgear at Munden MS35 in Mississauga with a new transformer and switchgear containing a circuit breaker and upgraded protections having new microprocessor relays. At the time of replacement, the age of the Pioneer 5 MVA, 27.6/4.16 kV transformer will be approaching end of life. The unit lacks a proper foundation, sitting on wood timbers, and is starting to lean. It is also leaking oil and lacks modern spill containment. The HV1 switchgear includes obsolete electromechanical relays and obsolete S&C Electric All Duty fused disconnect which has experienced several failures caused by animal contact. The condition of transformer cables, foundation and spill containment will be verified as the replacement date approaches and repaired/replaced as required.

11. Planned Circuit Breaker Replacement Markham TS#3 - E and Z Buses

This investment involves replacing the eight GEC PBOX 36 27.6 kV feeder circuit breakers at Markham TS#3. These circuit breakers have been identified as requiring replacement due to obsolescence and historical failures. Priority is high because this type of equipment has a history of premature failure and has the potential to affect a large number of customers in the event of a failure.

12. Station Switchgear Replacement Big Bay Point MS304

This investment involves replacing the 15 kV switchgear and primary circuit switcher at Big Bay Point MS304 in Barrie with switchgear having arc resistant construction and circuit breakers that meet Alectra Utilities' safety standard, upgrading protection with new microprocessor relays and replacing end-of-life feeder egress cables emanating from the feeder breaker positions in the new LV1 line up. The existing 15 kV switchgear is not arc-proof and presents a safety risk to personnel. It houses FEP SFA17 SF_6 circuit breakers which are obsolete in that they are no longer supported by the manufacture and parts are not readily available.

13. Capital Corrective Equipment Replacements - Stations

This investment is primarily driven by major deficiencies found through Alectra Utilities' regular inspection of their stations. Failure of major parts such as HV bushing, oil pumps or tap changer have significant impact in maintaining regular operation of the stations, affecting thousands of customers, and are therefore immediately addressed. Replacement of these parts often require considerable costs consisting of procurement of parts or equipment, contractor charges and/or internal labour cost. Examples of work funded by this investment are: replacement of tap changer component, replacement of cracked or failing HV bushing, and replacement of oil pump used for cooling.

Through the execution of this investment, Alectra Utilities' substation assets will continue to perform in a reliable and safe manner, with greatly minimized risks of asset failures and associated customer, safety and environmental impacts. Investments in substation assets are required to mitigate failure risks, which would have a major impact on customer outage frequency and duration, the environment and safety.

The Substation Renewal investments will target these station assets for replacement with up-to-date and standardized equipment that aligns with Alectra Utilities' current operational needs and requirements. The new standardized equipment ensure reliable asset performance and support the efficient execution of current maintenance practices.

2.1 Summary of Investment Outcomes and Benefits

Table A08 - 2 summarizes the outcomes and benefits associated with the Substation Renewal investment.

Table A08 - 2: Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Safety	• Ensure public and crew safety by replacing station assets that pose significant safety risks in the event of failure, including, in particular, the replacement of legacy non-arc proof switchgear units that may give rise to catastrophic flashovers and safety hazards with new arc-proof switchgear.
Reliability	• Ensure the reliable performance of Alectra Utilities' critical station infrastructure and overall distribution system by: • replacing deteriorated and functionally obsolescent station transformers, switchgear and breakers, which, if not replaced, may impact a high number of residential and commercial customers in the event of failure; and • increasing operational flexibility in terms of inter-station load transfer capabilities to maintain continuity of supply during scheduled or unscheduled outages.
Customer Value	• Deliver customer value by addressing station assets in need of replacement on a planned basis to minimize service disruptions, including by avoiding potentially prolonged outages due to the unavailability of spare parts and installing new standardized switchgear that will operate more rapidly to reduce overall impact on customers.
Environment	• Investments in substation assets are required to mitigate the risk of failure of power transformers, which contain large volumes of mineral insulating oils use as both an insulating and cooling medium. The consequences of substation power transformer failure may be significant, as they can lead directly

Outcome	Investment Benefits and Objectives
	to the catastrophic failure of protected equipment, which in turn can lead to customer interruptions, health and safety consequences, and adverse environmental impacts due to loss of oil containment and potentially fire.
Efficiency	• Support efficient control room operations and decision-making by replacing legacy switchgear that have limited automation and event-recording capabilities with new, standardized units that contain high-speed relays and provide enhanced event-recording, automation, control and field intelligence. • Reduce maintenance requirements relating to station circuit breakers as a result of the installation of new, standardized vacuum breakers that have fewer moving parts and that are more robust in terms of current interruption capabilities and structural durability through repeated switching operations.

III Investment Drivers and Need

3.1 Purpose

The Substation Renewal investment is primarily driven by the failure risk of station equipment due to their condition and lack of alignment with present day functionality. Given the critical importance of TS and MS infrastructure to the transformation and delivery of electricity across Alectra Utilities' service territory, it is paramount for the utility to identify and plan station renewal investments in a proactive and timely manner. The fact that substation asset failures can impact up to 10,000 customers for several hours or more means that an asset lifecycle approach relying on run-to-failure and reactive replacement is not appropriate unless robust contingencies exist (e.g., the ability to transfer/shed load seamlessly and sufficient spare components).

The planned investments are based on asset demographic information that Alectra Utilities gathers and tracks through ongoing monitoring and inspections (including visual observations, equipment testing, dissolved gas analysis, oil quality testing and transformer load monitoring). These findings provide the basis for condition assessment through the Asset Condition Assessment model, as a key input for SME evaluation of investment needs and alternatives. Details regarding the key characteristics and condition demographics of station power transformers, circuit breakers, and switchgear are provided in Section 3.2 below.

In addition to asset condition deterioration and failure risk, the Stations Renewal investment is also needed to address safety risks and the functional obsolescence of certain assets.

The older design of certain station equipment – which are already subject to elevated failure risks due to their age and condition – does not adequately protect against safety hazards arising from potentially catastrophic failures. As an example, legacy switchgear with non-arc flash design will be replaced with arc flash resistant switchgear, which include arc chutes to greatly minimize the safety impacts associated with a catastrophic flashover event.[91] These new switchgear also employ vacuum breakers, which are both safer and more protective of the environment in that they do not contain oil or SF6 which is a potent greenhouse gas. Other safety features include optical sensors that rapidly trip the upstream breaker in the event of an arc flash to significantly

[91] Arc-resistive switchgear construction is designed to divert arcs from the zone of operation (i.e., front, sides and back) out through the top of the switchgear and away from maintenance personnel.

reduce the energy delivered, and solid state trip devices to improve the safety margin for breaker operation compared to traditional thermal-magnetic protection. Additional features that will be considered include remote racking features and tools that enable staff to rack out the breakers at a safe distance when performing maintenance activities and a control delay function to effectively delay the operation of the breaker on energizing or de-energizing, so that crews have adequate time to move to a safe distance before the circuit breaker contacts are closed.

This investment will also replace assets that are functionally obsolete and difficult or impossible to maintain given the lack of available parts. Some equipment is no longer manufactured or supported by vendors on the market. In the event of failure, spare parts for such legacy equipment are scarce or unavailable, leading to extended outages during complex and difficult reactive repairs. An example is the DST2 and DST2-5 air magnetic circuit breakers, which utilize vintage technology to provide short circuit protection against faults. The manufacturer considers these units as being in the obsolete lifecycle phase, given that their production ended more than 30 years ago. Since these circuit breakers and associated spare parts are simply not available, a failed component would require Alectra Utilities to replace the entire circuit breaker assembly with a new breaker type and retrofit to install into existing vintage switchgear. Such reactive replacement would be costly and result in considerable outage impact for customers.

Table A08 - 3 lists the primary and secondary drivers of this investment:

Table A08 - 3: Investment Drivers

Investment Driver	Reasoning and Investment Benefits
Primary Driver: **Failure Risk**	This program is primarily driven by the risk of failure of the substation assets, targeting assets identified as being in the poorest condition according to ACA and HI results.
Secondary Driver: **Functional Obsolescence**	A number of station assets (particularly circuit breakers) are deemed technically and functionally obsolete. They need to be replaced through proactive and planned renewal, so as to reduce the impact of prolonged outages (i.e., due to unavailability of spare parts for equipment that is no longer supported or manufactured by vendors) and ensure alignment of critical station assets with Alectra Utilities' current system and customer demands.
Secondary Driver: **Safety**	The design of certain legacy station assets could create significant safety risks. In particular, Alectra Utilities needs to replace non-arc flash resistant switchgear with new, standardized units that protect workers against the potentially catastrophic impact of flashover events as well as other features to ensure that work is executed at station sites in a safe manner. Transformer ruptures resulting from catastrophic failure can results in fire and public safety risk
Secondary Driver: **Environmental**	Spill containment for older transformers may not meet modern-day standards. Loss of oil containment could result environmental contamination.

3.2 Asset Details

As discussed above, asset condition and demographics data are a key input for identifying replacement candidates as part of the Stations Renewal investment. To this extent, this section describes the salient characteristics and condition demographics of key station equipment (i.e., power transformers, switchgear, and circuit breakers), which underpin Alectra Utilities' ACA analysis and determination of needs and solutions for this investment.

3.2.1 Station Power Transformers

The investments in stations power transformers during the DSP period are to renew deteriorated assets. As set out below, the condition of the assets and other operational factors have informed the planned investments.

Alectra Utilities' fleet of power transformers gradually undergo internal degradation as they age and are subject to continuous loading and system faults. The paper insulation around the transformer winding will depolymerize over time into the transformer mineral oil, which is used to provide dielectric insulation protection within the transformer. Depolymerisation results in the oil losing its dielectric properties and in the paper insulation physically deteriorating over time. If the transformer is exposed to higher-than-normal internal temperatures, this degradation process will be accelerated. Eventually, once the paper insulation has fully deteriorated, a winding-to-winding fault will occur, resulting in the internal failure of the transformer. In a catastrophic failure, this internal fault will become extremely violent, leading to an explosion and fire. If there are insufficient firewalls or protections between adjacent transformer units, the damages from the failed unit will spread to the other transformer units and/or adjacent or connected assets.

The photograph below (Figure A08 - 1) shows a highly publicized explosive failure of a Hydro One transformer at Richview TS on March 18, 2011. There was no blast wall separating the failed transformer from an adjacent transformer. The explosion and resulting fire damaged the adjacent transformer as well as associated bus structure. These transformers also lacked modern-day spill containment, resulting is a substantial oil leak.

Figure A08 - 1: Explosive Failure of a Hydro One Transformer at Richview TS on March 18, 2011

The consequences of a substation power transformer failure may be significant, as it can lead directly to the catastrophic failure of protected equipment, which in turn can lead to customer interruptions, health and safety consequences, and adverse environmental impacts. The impact of a failed MS transformer is increased due to their proximity to residential and commercial areas. Safety issues related to this investment include the risk associated with failure, and a possible oil spill if the substation transformers were to rupture.

During the DSP period, Alectra Utilities plans to replace two stations transformer units. Figure A08 - 2 below presents the HI distribution of Alectra Utilities' fleet of power transformers. Thirty-four units are shown to be in the "Poor" condition category and two in the "Fair" condition category. Two units have been selected for replacement in the DSP planning period. The remaining units have been deferred based on discussions with subject matter experts and other considerations. The deferred units were selected based on non-conditional factors including station configuration (e.g., dual transformer configuration), station feeder interconnections and load transfer capabilities, availability of spare units and station decommissioning schedules. Transformer replacements deferred beyond the DSP planning period will be closely monitored and maintenance will be enhanced to maintain the asset where required.

Figure A08 - 2: Power Transformers Health Index Distribution

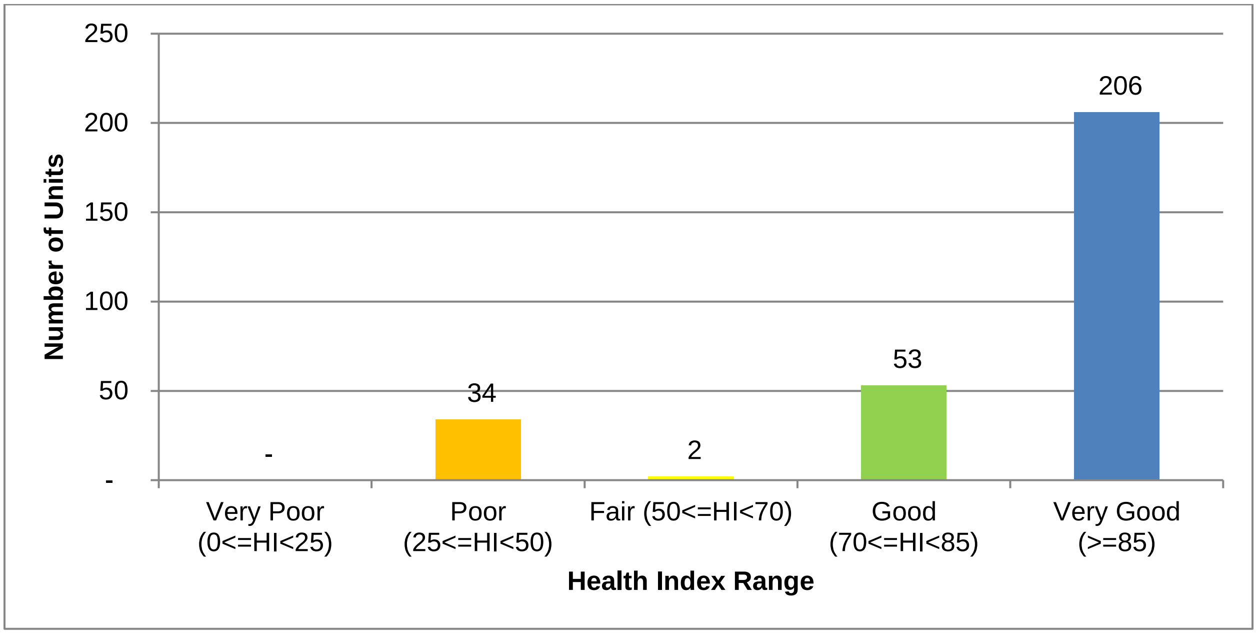
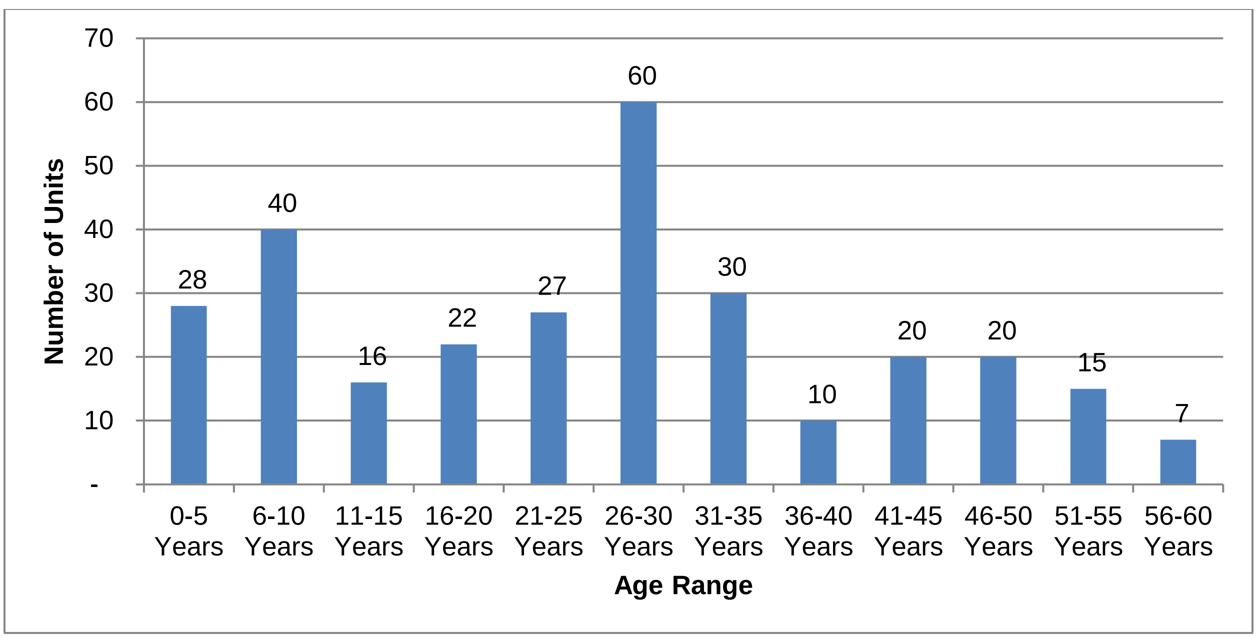


Figure A08 - 3 below shows the age distribution of Alectra Utilities' fleet of power transformers.

Figure A08 - 3: Power Transformers Age Distribution



Alectra Utilities' system has 295 power transformers, including 26 spare units. These are comprised of 31 TS transformers, three of which are spares, and 264 MS transformers which include 23 spares. As shown in Figure A08 - 3, 42 transformers are currently beyond their typical useful life of 45 years, including 9 units that are expected to exceed their maximum useful life of 60 years within the 2020-2024 period.[92] All units at or exceeding their useful life are smaller scale MS power transformers. All larger scale TS power transformers are within their useful life. Observations of useful life for power transformers is presented for high level information purposes only. HI models for power transformer includes an age component; however, the component is given a very low weighting as more specific condition data was available for condition assessments.

The power transformers' Health Index results were reviewed with subject matter experts in the Asset Condition Assessment, Station Design, Station Sustainment and System Planning departments. This consultative exercise examined a number of criteria to determine the course of action for those transformers identified in the asset condition assessment. The review considered criteria such as; 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, availability of spare transformers, safety and environmental concerns, and available budget.

Based on this consultative process, two transformers replacements were identified for replacement in the DSP planning period. In addition, Alectra Utilities will closely monitor the condition of its aging transformers.

3.2.2 Station Switchgear

The investments in stations switchgear during the DSP period are to renew deteriorated assets and those that may pose safety risks. Station switchgear includes breakers, disconnect switches, or fuse gear, current transformers ("CTs"), potential transformers ("PTs") and occasionally some or all of the following: metering, protective relays, internal DC and AC power, battery charger(s), and AC station service transformation. The primary driver for switchgear replacement is generally

[92] Asset Amortization Study for the Ontario Energy Board", Kinectrics Report No. K-418033-RA-001-R000, April 28, 2010.

the condition of the circuit breakers. Safety considerations associated with the switchgear are a secondary driver.

Figure A08 - 4 below presents the HI distribution of Alectra Utilities' fleet of switchgear units. Thirty-six units are shown to be in the "Poor" condition category and eight-one in the "Fair" condition category. Eleven units have been selected for replacement in the DSP planning period.

Figure A08 - 4: Station Switchgear Health Index Distribution

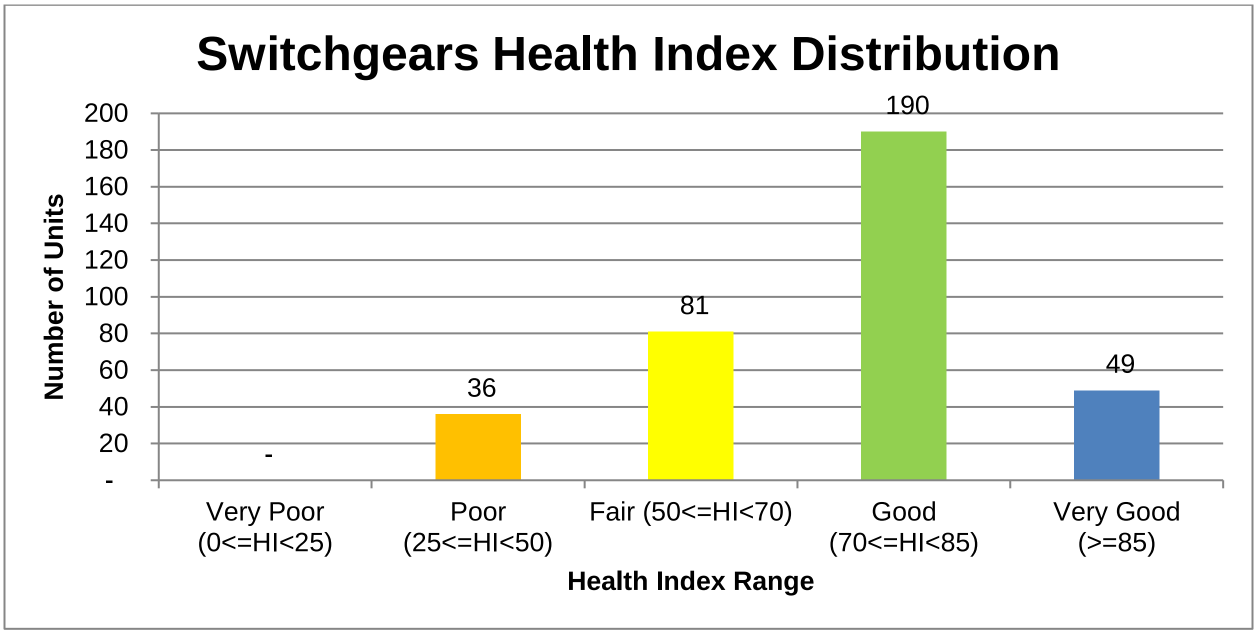
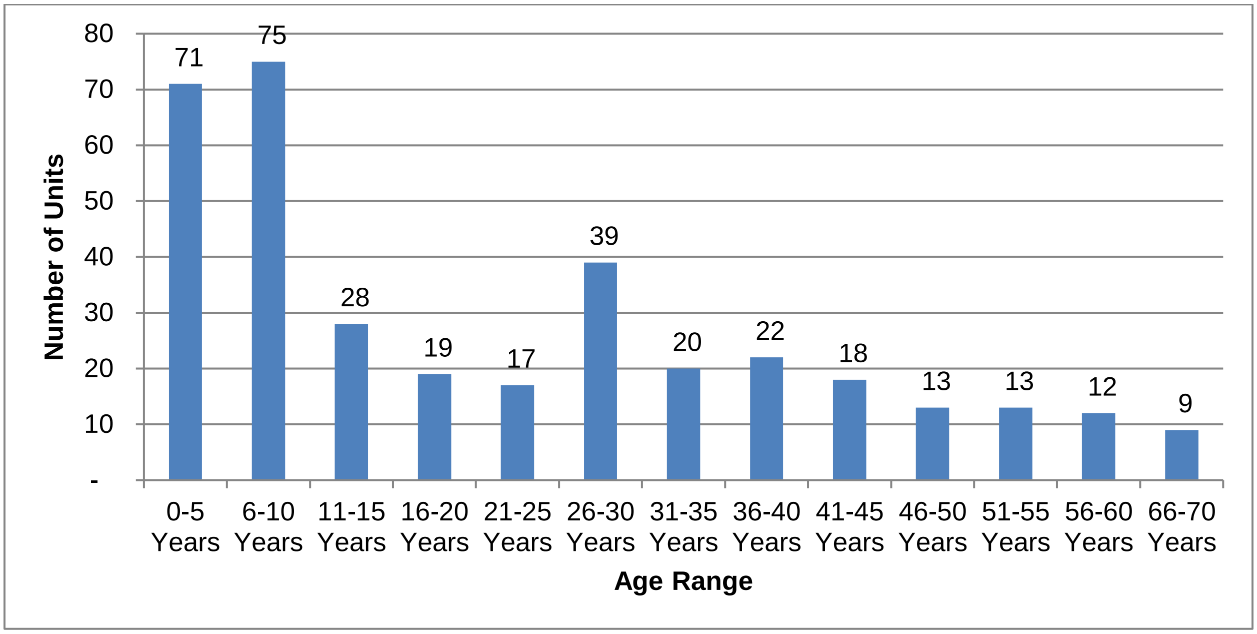


Figure A08 - 5 below shows the age distribution of Alectra Utilities' fleet of switchgear.

Figure A08 - 5: Station Switchgear Age Distribution



Alectra Utilities' distribution system has 356 station switchgear. As can be seen from Figure A08 - 5, 65 station switchgear are currently beyond their TUL of 40 years, 9 currently exceed their MUL of 60 years and 22 will exceed their MUL within the DSP planning horizon.

Legacy station switchgear assemblies are not arc rated and typically incorporate older technology relays, which have limited automation and event recording capabilities. Maintenance operations, such as the racking in and out of circuit breakers configured within non-arc-rated switchgear, are potentially dangerous. When performing such tasks, proper personal protection equipment ("PPE") and an arc flash boundary must be established and followed. While proper PPE will protect maintenance personnel from the hazards of arc flash to a certain degree, material safety risks remain. For instance, such PPE is designed to prevent burns to the body that could cause death, but provides little protection from the force of flying debris when an arc flash occurs.

The switchgear population identified in the Health Index results were reviewed with subject matter experts in the Asset Condition Assessment, Station Design, Station Sustainment, and System Planning departments. This consultative exercise examined a number of criteria to determine the course of action for those switchgear identified in the asset condition assessment. The review considered criteria such as; station decommissioning schedules associated with voltage conversion projects, capacity and operational constraints, peak loading levels, type of customers supplied, potential stranded load conditions, distribution system load transfer capabilities, availability of components, technical obsolescence, safety and environmental concerns, and available budget.

Based on this consultative process, eleven station switchgear replacements have been identified in the DSP planning period. Replacement of associated circuit breakers, protections and other ancillary equipment is included in the replacement of station switchgear. Alectra Utilities will manage constraints associated with non-arc flash rated switchgear remaining in service through the application of modified operating practices.

3.2.3 Station Circuit Breakers

The investments in circuit breakers during the DSP period are primarily driven by condition and the functional obsolescence of certain legacy and deteriorated assets. As set out below, the age and condition of these assets have both informed the planned investments in station circuit breakers.

Station circuit breakers can make, carry and interrupt electrical currents under normal and abnormal conditions. Circuit breakers are required to operate infrequently. However, when an electrical fault occurs, breakers must operate reliably and with adequate speed to minimize damage impact. Circuit breaker designs have evolved over time and many different varieties are currently in use at Alectra Utilities' stations. New switchgear will be equipped with vacuum circuit breakers. Alectra Utilities typically installs vacuum breakers indoors in metal-clad switchgear for all new installations. Current medium voltage vacuum breakers require low mechanical drive energy, have high endurance, can interrupt fully-rated short circuits up to 100 times, and operate reliably for over 30,000 or more switching operations, thereby making them an appropriate choice for replacement.

In the case of circuit breakers, they are closely tied to the switchgear assembly in which they operate. Circuit breaker replacements typically drive the replacement of non-arc flash resistant switchgear. The replacement of non-arc flash resistant switchgear also typically drives the replacement of the circuit breakers and protection and control relays that they house. In addition, the risk associated with "obsolete" circuit breakers is being mitigated to a certain extent by retaining old units that have been removed from service so that they can be used for parts.

Figure A08 - 6: Circuit Breakers Health Index Distribution

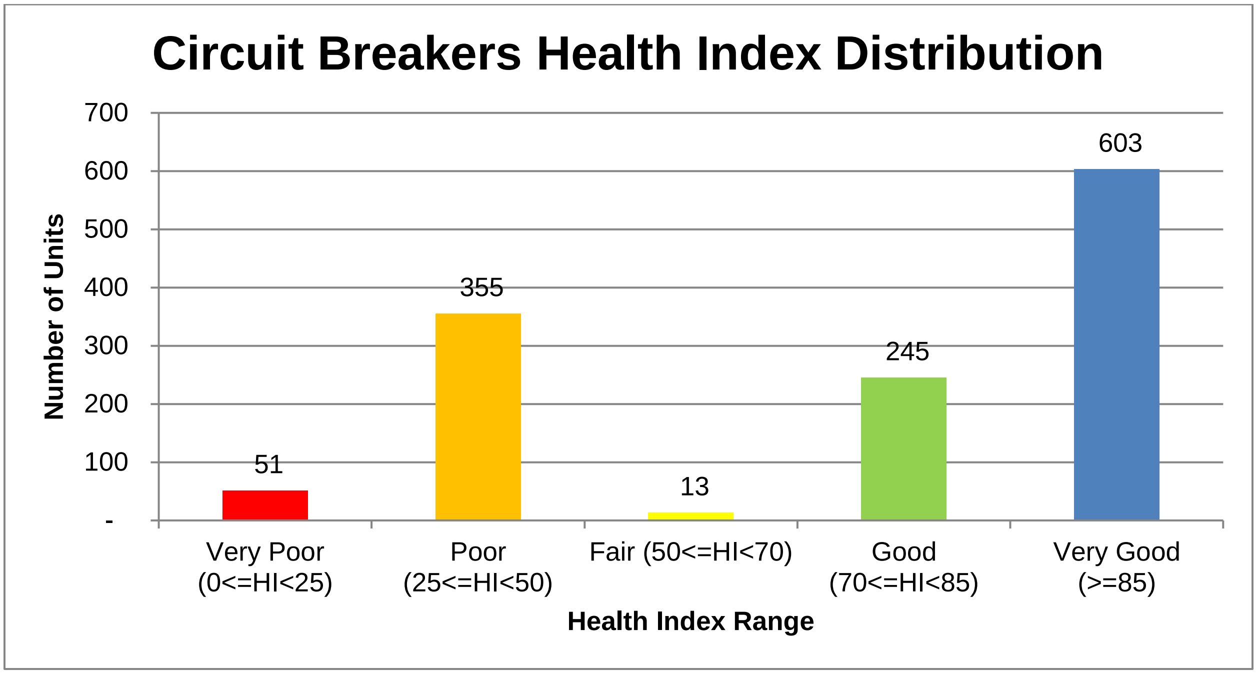
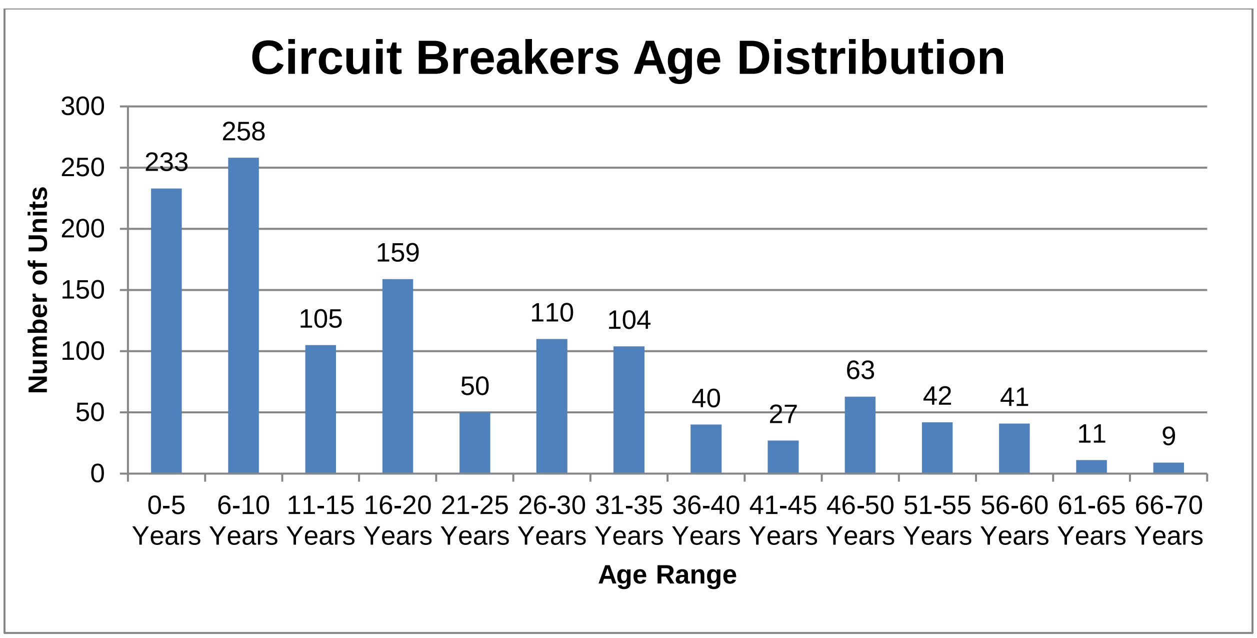


Figure A08 - 7 below shows the age distribution of Alectra Utilities' fleet of circuit breakers.

Figure A08 - 7: Circuit Breakers Age Distribution



Alectra Utilities' distribution system has 1,271 installed circuit breakers at its stations, 231 of which are associated with transformer stations. As can be seen from Figure A08 - 7, 193 circuit breakers are currently beyond their TUL of 40 years, 20 are currently beyond their MUL of 60 years and approximately 66 will exceed their MUL within the DSP planning horizon.

Certain vintage circuit breakers are a concern, as they have become slow to operate, resulting in longer fault duration times and increased energy dissipation due to arc faults that can affect the integrity of equipment, and pose a safety hazard to operations personnel. This asset degradation is a result of the effects of multiple breaker operations over the life of the asset. There are also safety concerns related to the general nature of switchgear materials and housing design. Electrical short circuits and faults are extremely dangerous, and potentially fatal to personnel. Arc flash occurs when phase conductors are shorted and ionization of the air occurs. When this happens, the arc faults produce large amounts of heat in radiated form, which can severely burn the skin and set clothing on fire. Also, during an arc flash, hot arc plasma and molten metal is blasted from the fault location outward in a radial direction at such high speeds, that impact can be deadly.

Exposure to the risk of arcing faults includes all of the following:

- Radiated thermal energy;
- Shock hazard due to touching energized conductors;
- Expanding gases, known as arc blasts, which can cause:
    - Flying debris;
    - Pressure (shock) waves that can knock a person off balance;
    - Sound waves that can cause ear damage.
- Bright light (from arc plasma), which can result in temporary or permanent blindness;
- Arc plasma or heat that can result in a fire;
- Metal vaporization which can splatter on surfaces and will condense on cooler materials.

The Health Index results were reviewed with subject matter experts in the Asset Condition Assessment, Station Design, Station Sustainment, and System Planning departments. This consultative exercise examined a number of criteria to determine the course of action for those circuit breakers identified in the asset condition assessment. The review considered criteria such as; station decommissioning schedules associated with voltage conversion projects, capacity constraints, peak loading levels, type of customers supplied, potential stranded load conditions, distribution system load transfer capabilities, availability of circuit breakers and components, technical obsolescence, environmental concerns, and available budget.

Forty-eight circuit breaker replacements have been identified in the DSP planning period. Eight of these are TS circuit breakers. The remainder of the circuit breakers are at municipal stations. The MS circuit breakers are to be replaced along with their associated switchgear and protections. Obsolete circuit breakers that have been removed from service will be harvested for parts so as to help to mitigate risks associated with those obsolete circuit breakers that continue to remain in service.

3.3 Integrated and Station-centric Planning Approach

Through integrated and station-centric planning, Alectra Utilities takes a holistic and systematic approach to evaluating all relevant information with the view of deriving an accurate picture of the risk profile of relevant assets at each TS or MS site. As a starting point, station asset inspections and testing (including dissolved gas and oil quality testing, as well as load monitoring, of power transformers) are important to generating the necessary asset data and field intelligence that underpins the entire planning and decision-making process.

In addition to HI results, Alectra Utilities' strategy in managing station assets involves the evaluation of multiple factors to assess and mitigate the risk profile at any given station:

- Station configuration: Alectra Utilities' stations utilize both single and dual element arrangements (referring to a station's number of transformers). 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 associated risk at the station and accordingly determine the need and timing for replacing either transformer.

- Inter-station connectivity and back up: All of Alectra Utilities' substations 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 spares for power transformers, circuit breakers, and other equipment 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 (including spares that are moved to stations due to higher risk profiles) or stored in inventory.

- Station peak loading: Alectra Utilities monitors station loading on a continuous basis, capturing hourly peak load values throughout the year. In the event that 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 investments: Through an integrated planning process, Alectra Utilities will identify station sites where upgrades are required and the associated timing. The Asset Management team, in consultation with Station Sustainment, will assess the risk profile of relevant station transformers 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 other potential refurbishment activities. If transformers that have been replaced are in Fair or Good condition, they may be tested, refurbished and maintained as spare units.

- Station decommissioning schedules: As described in Appendix A06 – Part B, 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 investments, in which case, the associated substations would be decommissioned. These voltage conversion investments will allow Alectra Utilities to avoid capital investments that would otherwise be required in certain stations that supply older, lower-voltage feeders. It would not be prudent to invest in renewing assets in stations that are scheduled to be decommissioned. The risk profile of municipal stations identified in these conversion areas are assessed in consideration of the schedule for their decommissioning to determine the level of investment required to maintain the station assets as compared to replacement. These station assets may be maintained or refurbished to ensure continued reliable operation in the interim.

As a key input for purposes of station asset replacement decisions, HI results for major station assets are compiled for each station. Alectra Utilities considers HI results along with other input, including the six factors considered above, station maintenance history, station component performance issues, and station component replacement initiatives not managed through the ACA process, such as transformer tank and radiator reconditioning, transformer leak mitigation/re-gasketing and the need to replace asset subcomponents.

In alignment with its station-centric investment planning approach, Alectra Utilities considers the condition of all major assets located within a given station and completes thorough evaluation to identify assets that warrant follow-up action plans as well as opportunities to bundle work by station. Other than the aforementioned input factors, Alectra Utilities also considers station decommissioning schedules associated with voltage conversion initiatives, future expansion requirements, capacity constraints, magnitude and criticality of the load that is supplied, type of customers supplied, potential stranded load conditions, load transfer and shedding capabilities, obsolescence issues, availability of spare parts, operating protocols, maintainability, safety and environmental concerns and budgetary constraints. Based on this evaluation, business cases are prepared for the identified assets, integrating all applicable cross-functional drivers as part of Alectra Utilities' integrated planning process.

IV Investment Timing and Pacing

4.1 Summary of Expenditures

Table A08 - 4 provides the year-over-year breakdown of Stations Renewal investments, including the historical period from 2015-2018, the bridge year in 2019, and the future period from 2020-2024.

Table A08 - 4: Historical and Proposed Investment Spending

	Historical Expenditure				Bridge	Forecast Expenditure				
Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CAPEX ($MM)	$9.6	$10.6	$9.1	$10.4	$5.0	$12.8	$4.4	$2.8	$3.2	$5.5

4.2 Historical Expenditures (2015-2019)

Historical expenditures between 2015 and 2019 total $44.7 MM, which focused on the replacement of substation assets, including power transformers, station switchgear and circuit breaker assets. The fluctuation in spending within this period, particularly the reduced spending in 2019, is the result of operational and system constraints that prevented the same volume of substation renewal work from being accomplished within those years.

4.3 Future Expenditures (2020-2024)

Future expenditures from 2020 to 2024 will total $28.7 MM. These expenditures continue the replacement of major substation assets, including power transformers, station switchgear and circuit breaker assets, as well as the procurement of critical spare equipment.

In Alectra Utilities' practice, investment portfolio optimization is performed using the Copperleaf C55 system, which provides an optimal capital portfolio that balances financial and resource driven constraints as well as investment benefits and risks in alignment with corporate strategic objectives. The 2020 to 2024 optimization resulted in lower funding allocated to station renewal investments when compared to the historical period. The needs for station renewal investments were evaluated against other investment needs in the investment portfolio optimization process, and due to higher value provided by other investments, some stations investments were deferred beyond the DSP planning period**.** The deferred projects were evaluated for risk as well as non-condition based factors including, station configuration (e.g. dual transformer configuration), station feeder interconnections and load transfer capabilities, availability of spare units and station decommissioning schedules. Deferred assets will be closely monitored and maintenance will be enhanced, as required, to maintain these assets.

4.4 Investment Pacing and Prioritization

Alectra Utilities leverages the asset condition information provided by its ACA models to generate asset health indices for individual station components. The HI results of the ACA are reviewed with subject matter experts in multiple departments to surface those assets most warranting follow-up activities, to ascertain whether a business case should be processed, and if cross functional drivers are involved. Business cases are prepared and processed through Alectra Utilities' C55 optimization application where each business case is evaluated based on a multivariable value framework. Business cases are optimized and investments providing the highest value are advanced while the timing of investments providing lower value may be adjusted, or deferred. For more detailed information regarding this process see section 5.4.1.

4.5 Execution Approach

Alectra Utilities conducts formal project management, from developing investment scope details through to work execution. This ensures that investments are managed effectively throughout their project lifecycle and that adequate oversight is applied for change management. Formal processes are followed to initiate, plan, execute, monitor and control each investment within Alectra Utilities' portfolio of investments.

Alectra Utilities optimizes investments to align with financial and resource constraints and organizational capabilities. Alectra Utilities will utilize internal staff and external contractors to complete the renewals proposed for investments. Alectra Utilities has retained external contractors working at different work sites throughout the year under a multi-year Master Service Agreement, to support Alectra Utilities' work requirements. This protects pricing and ensures resource availability from contractors.

For larger investments, the identification of project scopes are confirmed and formal designs typically commence one year in advance. This enables Alectra Utilities staff to perform investigative field analysis required to build comprehensive and thorough design products, with high quality material take offs and identification of and processing of external approvals, required for successful implementation of the work. Advanced designs facilitate allocation of long lead time items with sufficient lead time with the potential to capitalize on volume purchase agreements where possible.

Alectra Utilities' internal project management methodology provides specific guidelines, procedures, work instructions, and industry best practices that allows work to be performed in an economically efficient, cost effective, and safe manner.

V Options Analysis

Alectra Utilities has considered the following options to manage the deteriorating and functionally obsolete station assets within its service area. These include the following:

5.1 Transformers

Option 1. Replace all transformers exceeding TUL and deemed to be in the "Poor" condition category

Option 2. Do nothing

Option 3. Conduct an in-depth review with SMEs considering factors already described in the narrative. For those assets covered in point #1 not being replaced, install on-line monitoring and/or increase condition monitoring and maintenance as deemed necessary.

The transformer condition assessments identified 34 transformers in poor condition. The cost to replace these units is high and not warranted at this time as alternative solutions exist. This option was rejected. The do nothing option was also rejected as the failure risk was deemed to be too high. Option 3, is the preferred option. Using a combination of condition monitoring and increased maintenance, will provide continued service life.

5.2 Station Switchgear

Option 1. Replace all switchgear exceeding TUL or deemed to be in the "Poor" condition category.

Option 2. Do nothing

Option 3. Conduct an in-depth review with SMEs considering factors already described in the narrative. For those assets covered in point #1 not being replaced, increase condition monitoring and maintenance as deemed necessary and observe appropriate operating protocols for non-arc resistant switchgear. For the switchgear replacements driven by circuit breaker replacement, replace the breakers in the existing switchgear.

Switchgear condition assessments identified 36 units in the Poor condition and none in Very Poor. The cost to replace all 36 switchgear is very high and not warranted. This option was rejected. The do nothing option was also rejected as the failure risk was deemed to be too high. The preferred solution is Option 3, conduct an in-depth review with SMEs considering factors already described in the narrative. For those assets covered in point #1 not being replaced, increase condition monitoring and maintenance as deemed necessary and observe appropriate operating protocols for non-arc resistant switchgear. For the switchgear replacements driven by circuit breaker replacement, replace the breakers in the existing switchgear.

5.3 Circuit breakers

Option 1. Replace all circuit breakers exceeding TUL or deemed to be in the ”Very Poor” or “Poor” condition category.

Option 2. Do nothing

Option 3. Conduct an in-depth review with SMEs considering factors already described in the narrative. For those assets covered in point #1 not being replaced, increase condition monitoring and maintenance as deemed necessary and retain parts from obsolete units that are being replaced.

Circuit breaker condition assessments identified 51 breakers in Very Poor and 355 units in the Poor categories. While some breakers in the Very Poor category must be replaced, the cost to replace all circuit breakers is high and was rejected. The do nothing option was also rejected as the failure risk was deemed to be too high. Option 3, is the preferred option. Circuit breakers not replaced will undergo a combination of increased condition monitoring and maintenance. Spare breaker parts from recovered units will refurbished and retained as spares.

It is important to note that circuit breakers are closely tied to the switchgear assembly in which they operate. Circuit breaker replacements typically drive the replacement of non-arc flash resistant switchgear. The replacement of non-arc flash resistant switchgear also typically drives the replacement of the circuit breakers and protection and control relays that they house.

VI Investments

The material investments from 2020 to 2024 that form the Substation Renewal investments are included in Table A08 - 5.

Table A08 - 5: Material Projects and Initiatives

Project Code	Project Name	CAPEX ($MM)
150637	Station Switchgear Replacement - MS10	$2.6
150677	Station Switchgear Replacement - Aquitaine MS59 LV1	$1.7
151098	Station Switchgear Replacement - Battleford MS54 LV1	$1.3
150699	Station Switchgear Replacement - Shawson MS43 LV1	$1.1
102728	Station Switchgear Replacement - Big Bay Point MS304	$1.1

Appendix A09 - Transformer Renewal

I Overview

The Transformer Renewal investment targets the replacement of transformers exhibiting safety and environmental risks. In addition, Alectra Utilities plans to replace functionally obsolete transformers (e.g., undersized transformers and transformers of a non-standard legacy configuration), transformers without adequate redundancy, and transformers that are otherwise difficult to restore in the event of failure resulting in extended outages.

Table A09 - 1 below provides an overview of the 2015-2018 historical period spending, the 2019 bridge year, the 2020-2024 forecast DSP period spending, as well as investment's drivers and associated outcomes.

Table A09 - 1: Investment Subgroup Summary

	Historical Expenditure				Bridge	Forecasted Expenditure				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$14.7	$10.9	$11.5	$14.0	$12.3	$5.5	$6.3	$7.0	$7.4	$7.8
Primary Driver:	Failure Risk									
Secondary Drivers:	Reliability, Public Safety, Environmental Risk									
Outcomes:	Customer Value, Reliability, Safety, Environment									

II Investment Description

Through this investment, Alectra Utilities' plans to replace high-risk overhead and underground transformers (e.g. pole-mounted, padmounted and vault transformers) with new transformers that conform to present day standards. Specifically, Alectra Utilities plans to replace transformers that pose safety or environmental risks, are at high risk of failure due to their condition or functional obsolescence, are inaccessible, or provide insufficient redundancy and therefore pose a reliability risk.

Alectra Utilities has 124,955 distribution transformers in service, which are vital to the provisioning of electrical supply to Alectra Utilities' customers. Depending on the customers and type of load they serve, Alectra Utilities' distribution transformers may be single-phase or three-phase, and range from 50 kVA in capacity (i.e., supplying a few residential customers) up to 3,000 kVA (i.e., supplying industrial, large commercial or multi-unit/high-rise residential customers). All distribution transformers being addressed by this investment contain mineral oil as the insulating and cooling medium.

Distribution transformers are typically operated based on a run-to-failure scenario, meaning the transformer will not be replaced based on probability of failure and will remain in service until it fails and causes an outage to customers, unless the transformer's condition has degraded that it poses specific risks. Alectra Utilities uses the criteria listed below to assess when a transformer should be replaced proactively:

i. Mitigation of safety and environmental risks

As discussed in Section 5.3.3 of the DSP, Alectra Utilities' asset management strategy for distribution class transformers follows a run-to-failure approach. However, when transformers exhibit safety hazards (e.g., corroded or damaged enclosure that may expose the public to energized components), or risk of environmental contamination (e.g., leaking oil), they will be replaced proactively. Any transformer exhibiting these risks is classified as being in poor or very poor condition through the Asset Condition Assessment (ACA) process**.**

ii. Mitigation of failure risks and reliability impact

a. Risk due to functional obsolescence

This investment will also target legacy transformers that are functionally obsolete and no longer align with current standards. Such transformers are also more likely to be overloaded, given the increase in area loads since their installation. The new transformers to be used for replacement will be sized appropriately in relation to customer demand at the relevant locations, which will prevent accelerated degradation of transformers due to overloading conditions.

b. Risk due to inadequate redundancy or difficulty of access

This investment will also target legacy transformers for which spares or backup are unavailable, or that are installed in hard-to-reach locations such as underground chamber, below-grade vaults, basements, and low-ceiling areas. When such transformers fail, there is a greater risk of extended outages. Emergency power supply is required which impacts restoration costs. In addition, specialized equipment, which is not always readily available, may be required for removal and installation of the assets located in these spaces. Therefore, planned replacement of these assets would mitigate lengthy customer outages. Planned replacement also provides opportunity to provide an alternative supply or relocate these assets to easily accessible locations.

Alectra Utilities plans to prioritize the replacement of transformers based on the Health Index (HI) score of the specific assets, prioritizing units in the worst condition.

2.1 Summary of Investment Outcomes and Benefits

Table A09 - 2 summarizes the outcomes and benefits associated with the Transformer Renewal investment.

Table A09 - 2: Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Customer Value	Deliver customer value by addressing transformers in need of replacement on a proactive and planned basis, which will minimize disruptions in service to customers (including as a result of potentially prolonged outages in the event of emergency reactive replacements of failed transformers)
Reliability	Ensure the reliable performance of Alectra Utilities' distribution system by replacing hazardous, obsolescent or overloaded distribution transformers, which will contribute toward system-wide and feeder-level reliability by: • minimizing duration of outages • minimizing unplanned outages • reducing probability of untimely failure due to overloaded assets
Safety	The replacement of hazardous transformers will minimize safety risk to the public, i.e., exposure of energized equipment to potential public access due to transformer enclosures that have been structurally compromised.
Environment	Catastrophic transformer failures can result in high environmental impacts and costs due to the spill of mineral oil. The replacement of transformers that exhibit moderate to major leaking will mitigate the likelihood of such environmental impacts.

III Investment Drivers and Need

The primary and secondary drivers are described in Table A09 - 3. Both drivers are discussed in more detail in sections 3.1 and 3.2, below.

Table A09 - 3: Investment Drivers

Investment Driver	Reasoning and Investment Benefits
Primary Driver: **Failure risk**	The primary driver for these investments is the elevated risk of failure, posing risk to safety and environment and leading to poorer reliability for Alectra Utilities' customers.
Secondary Driver: **Public safety, Environmental contamination and Reliability Impact**	The secondary driver for these investments is the mitigation of public safety risk due to deterioration of the physical transformer structure, compromising the secure access to energized components, the mitigation of the environmental contamination risk resulting from the loss of oil containment, and the mitigation of elevated risk of failure, from transformers exhibiting risks associated with public safety and environmental contamination, and risks associated with functional obsolescence, inadequate redundancy and difficulty of access, that lead to reduced reliability for Alectra Utilities customers.

3.1 Public safety and environmental contamination

In compliance with the established inspection requirement by the OEB, Alectra Utilities inspects distribution transformer every three years.[93] The conditions of the transformers captured during these inspections are factored in the ACA process, specifically in the calculation of the transformer Health Index.

Alectra Utilities believes there are over 5,000 in-service transformers, across Alectra Utilities' service territory, exhibiting safety hazards or risk of environmental contamination.

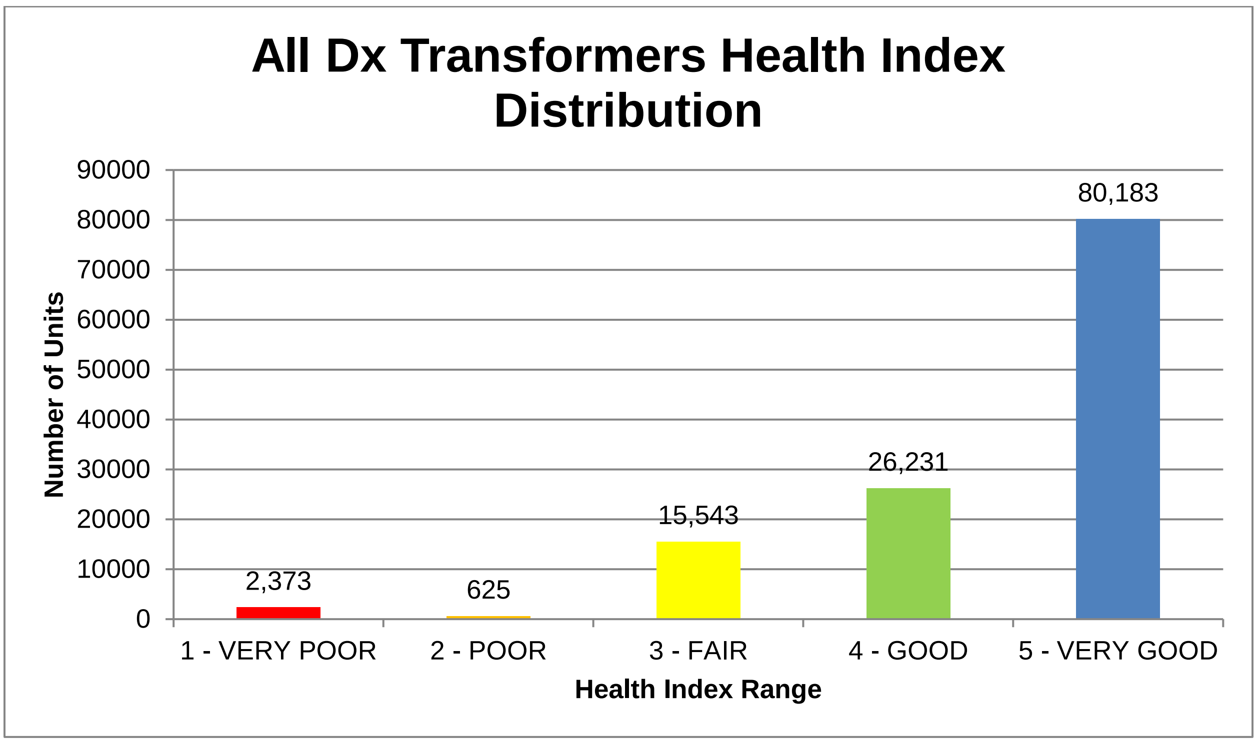
Through the ACA process, Alectra Utilities identified 2,998 transformer units in the Very Poor and Poor HI category as illustrated in Figure A09 - 1. All transformers in the Very Poor and Poor HI

[93] Distribution System Code "Appendix C – Minimum Inspection Requirements."

categories exhibit varying degrees of deterioration, moderate to major oil leak or corrosion, posing risks to public safety and environmental contamination and therefore, are targeted for proactive replacement.

Alectra Utilities believes the population of Very Poor and Poor units is understated due to lack of granularity of transformer inspection results in Alectra Utilities' East service area. Harmonizing inspection practices, Alectra Utilities introduced a more robust transformer inspection process in the East service area in 2018. During the 2018 transformer inspections, 870 units were found to have moderate to major oil leak or corrosion out of 14,568 units inspected in the East service area. At this rate, Alectra Utilities projects to find more than 2,000 units exhibiting safety and environmental risks, when it completes the three-year inspection cycle. Therefore, Alectra Utilities will target additional 2,000 units for proactive replacement during the five-year DSP period.

Figure A09 - 1: Distribution Transformer Condition Demographics



Transformers with excessive rust and corrosion can result in holes forming within the enclosure, which can result in live connections becoming exposed, creating a potential public safety risk.

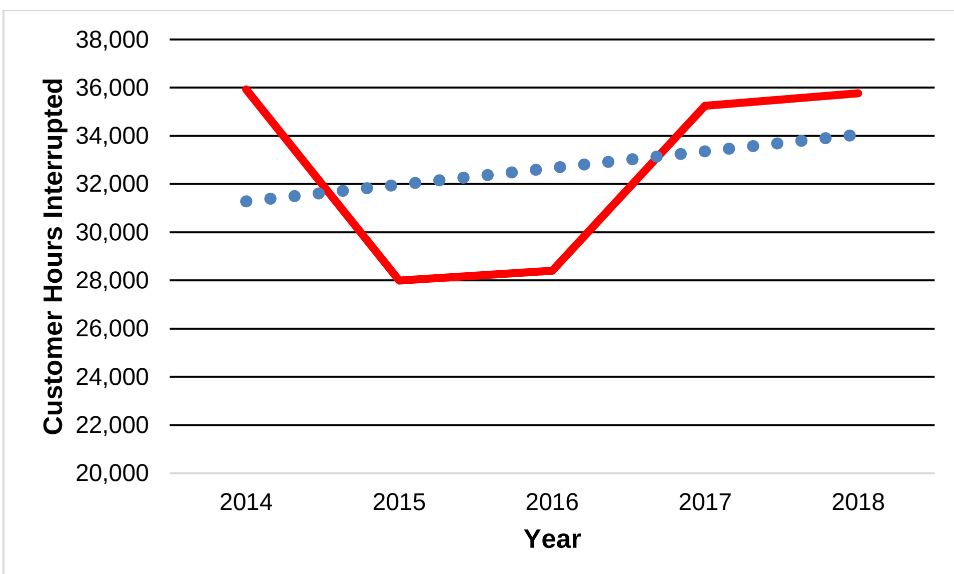
With respect to oil leaks, Alectra Utilities is subject to environmental legislation which deals with managing oil spills occurring from Alectra Utilities' in-service oil filled asset (e.g. transformers).

This environmental legislation includes Ontario Regulation 675/98 enacted under *Environmental Protection Act,* RSO 1990, E. 19 and the PCB Regulations (SOR/2008-273), enacted under *Canadian Environmental Protection Act, 1999.* Under the O. Reg. 675/98, Alectra Utilities is required to report all spills of 100 litres or more of oil into the environment. Once the spills of 100 litres occur from Alectra Utilities' transformers, Alectra Utilities is required to report and make immediate arrangements for remediation of the site where the transformer oil leak occurred. Under the PCB Regulations, Alectra Utilities is required to report any spills involving more than one gram of PCB into the environment. Under this scenario, Alectra Utilities is required to carry out full environmental remediation of the site where the transformer oil leak occurred.

3.2 Failure Risk and Reliability Impact

Failing transformers are increasingly impacting customers' reliability. Figure A09 - 2 provides details on the historical performance of distribution transformers over the five-year period from 2014 to 2018.

Figure A09 - 2: Distribution Transformers – Customer Hours Interrupted ("CHI")



In order to mitigate this trend, Alectra Utilities plans to replace specific transformers that are either more likely to fail due to functional obsolescence, or to result in prolonged outages upon failure. Alectra Utilities has identified 900 such transformers. These transformers are either more likely to fail (due to over-loading or other functional obsolescence), or to disproportionately affect reliability on failure due to lack of redundancy, or their lack of accessibility.

Functionally Obsolete, Over-loaded Transformers

Overloaded transformers are functionally obsolete since these units are undersized for the customers' demand. Operating under an overloaded state accelerates the deterioration of the transformer's insulation ultimately leading to failure.

Lack of Redundancy and Poor Accessibility

Transformers that have inadequate redundancy pose the risk of extended outages because of the lack of backup supply or spare inventory. A major benefit of planned replacement in these situations (as opposed to running these units until failure) is to provide looped supply, which creates a backup source of power in the event of a transformer failure.

Some legacy construction locations have transformers installed in locations that are difficult to access, which can significantly slow the process of restoration or reactive replacement. For example, locations below grade, in basements, underground chambers or low-ceiling areas. These locations provide access challenges when responding to transformer failures. Reactive replacement of transformers in these hard-to-reach locations present logistical challenges which result in prolonged outages and increased cost of replacement. By replacing and relocating these transformers proactively, Alectra Utilities can mitigate risks of unplanned, lengthy outages.

Alectra Utilities identified 900 units that exhibit risks associated with functional obsolescence, inadequate redundancy and difficulty of access. These are the units targeted for the 2020 to 2024 investments, further discussed in Section V.

3.3 Need

During the DSP period, the Transformer Renewal investment is designed to replace transformers exhibiting the following conditions:

- **Safety risk** - Significant rust or corrosion that damages transformer enclosure and potentially exposes the public to energized equipment
- **Environmental risk** – Leaking oil or containing PCB
- **Functional Obsolescence** – Consistent and significant overloading of the transformer
- **Lack of Redundancy** – Transformers without adequate redundancy or located in difficult to access spaces

While it is prudent to operate transformers on run-to-failure strategy, operating transformers that exhibit any of the conditions above following the same strategy is not prudent due to the higher consequence of failure.

Addressing the identified transformers on a proactive basis ultimately reduces costs for Alectra Utilities and for customers:

1. **Environmental Stewardship and Remediation Costs:** Environmental remediation increases over time as leaking transformers remain in service. From 2013 to 2016, Alectra Utilities spent approximately $5.6M (average $50k per site) for environmental remediation due to leaking transformers.
2. **Proactive Replacement is more Cost-Effective:** Emergency response to failure of transformers that lack adequate redundancy, or difficult to access would increase logistical costs, require labour hours, and unplanned rental of specialized equipment. Costs to replace the failed units reactively, should they fail outside of normal working hours, is higher than planned replacements when completed during normal working hours.

IV Investment Timing and Pacing

4.1 Summary of Expenditures

Table A09 - 4 provides the year-over-year breakdown of transformer renewal investment spending, including the historical period from 2015-2018, the bridge year in 2019, and the future period from 2020-2024.

Table A09 - 4: Historical and Proposed Investment Spending

	Historical Expenditure				Bridge	Forecast Expenditure				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$14.7	$10.9	$11.5	$14.0	$12.3	$5.5	$6.3	$7.0	$7.4	$7.8

4.2 Historical Expenditures (2015-2019)

Actual historical expenditures from 2015 to 2018 and 2019 as bridge year total $63.4 MM. Over that period, the investment included the backlog transformer replacement project in Alectra Utilities' Central South operating area, which is a one-time project to mitigate a backlog of hazardous transformers. The backlog project will conclude by the end of 2019.

4.3 Future Expenditures (2020-2024)

Future expenditures between 2020 and 2024 total $34MM. In general, the yearly investment is less than historical expenditures as the backlog project to replace the leaking transformers in Alectra Utilities' Central South will be completed in 2019. From 2020 onwards the investment will target the subset of transformers that require proactive replacement as defined in Section 3.3.

4.4 Investment Pacing and Prioritization

Each year, Alectra Utilities carries out the annual inspection program to approximately 1/3 of the transformer population, then on a prioritized basis, will review, and select the most deteriorated and hazardous transformer units for replacement. The locations and priority are determined based on the results from the ACA process, along with stakeholder engagement between Asset Management, Operations, System Control, and Capital Design. It is expected that every year as we continue the annual inspection program, we will identify new units that are in hazardous states and requiring replacement.

V Options Analysis

Through the annual ACA, Alectra Utilities had identified 2,998 transformers in Very Poor or Poor condition. Based on present day assessment of system-wide renewals, Alectra Utilities' plans to replace 1,148 of the 2,998 transformers through other funded projects, leaving 1,850 transformers to be replaced through the Transformer Renewal portfolio.

In addition, Alectra Utilities has identified 900 transformers that are required to be replaced due to functional obsolescence, inadequate redundancy and difficulty of access.

As discussed in Section 3.1, over the next five years, with ongoing inspections, Alectra Utilities expects to find another 2,000 deteriorated and hazardous transformers that will require replacements as well.

These quantities form the three investment options shown in Table A09 - 5.

Table A09 - 5. Pacing Options for Transformer Renewal

Strategy	Plan Period (years)	Total Quantity	Quantity per year	Average Transformer Replacement Plan Cost per year
Strategy 1: Accelerated Pace	5	4,750	**950**	$11.5M
Strategy 2: Moderate Pace	5	2,750	**550**	$6.8M
Strategy 3: Reduced Pace	5	1,850	**370**	$4.5M

Strategy 1 (Accelerated Pace) will address 4,750 transformers: those currently in and forecast to be in Very Poor or Poor condition over the DSP period, as well as all transformers that are functionally obsolete, lack adequate redundancy or are difficult to access. This approach will mitigate the risks associated with public safety and the environment. In addition, this option will replace units that are projected to fail during the DSP planning period. Alectra Utilities anticipates that while this scenario will improve Alectra Utilities' reliability due to failing transformers, however, Alectra Utilities, being cautious about spending, believes this approach also carries a significant cost. Therefore, this option is not recommended.

Strategy 2 (Moderate Pace) will address 2,750 transformers: those currently in Very Poor or Poor condition, as well as all transformers that are functionally obsolete, lack adequate redundancy or are difficult to access. This approach will proactively replace units that pose a safety or environment risks or would cause extremely long duration outages to customers. Although this approach introduces additional risk relative to the Accelerated Pace option, the cost is lower over the DSP period. Alectra selected this approach because it strikes a balance between risk and cost for this asset class.

Strategy 3 (Reduced Pace) will address only the 1,850 transformers currently in Very Poor or Poor condition. Although this option will mitigate the risks of public safety and environmental remediation, it will not maintain reliability as it does not mitigate the risks of unplanned lengthy outages.

Figure A09 - 3 illustrates the annual spending requirements from 2020 to 2024 resulting from Alectra Utilities' planned approach.

Figure A09 - 3: Recommended Annual Spending Requirements (2020 – 2024)

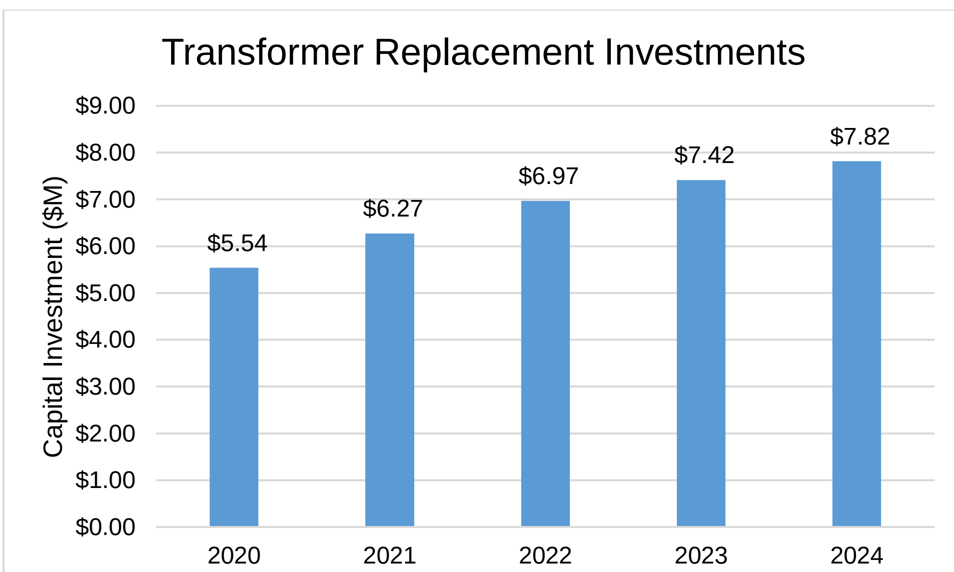
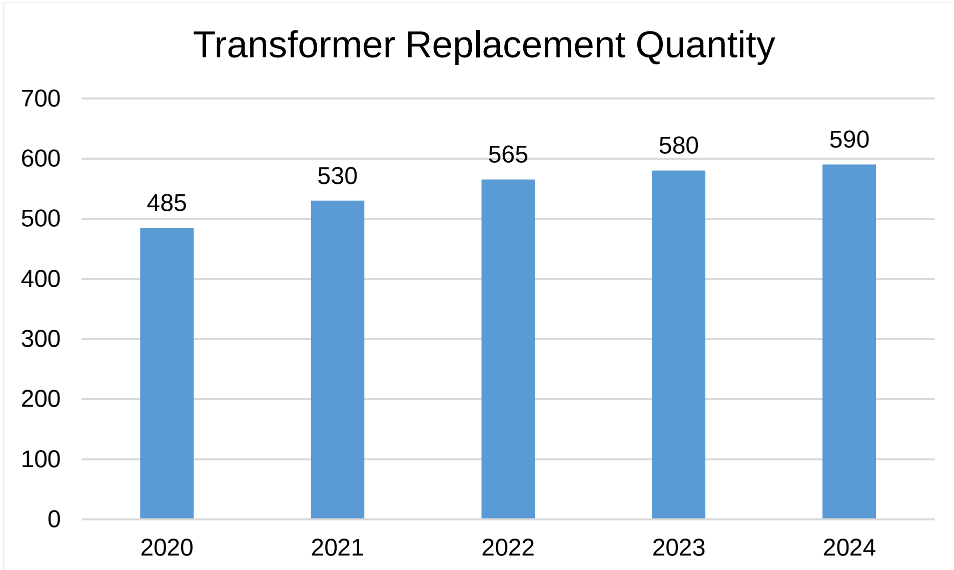


Figure A09 - 4 illustrates the annual quantity to be replaced from 2020 to 2024 under Alectra Utilities' planned approach.

Figure A09 - 4: Recommended Annual Quantity to be Replaced (2020 – 2024)



5.1 Execution Approach

Alectra Utilities will leverage internal and external contractors to complete the design and construction of the new transformers to be installed within the system. Alectra Utilities has retained external contractors working at different work sites throughout the year under a multi-year engineering procurement construction (EPC) Master Service Agreement. Regular progress meetings are held to ensure technical and operational issues are resolved promptly.

The Execution phase will follow Alectra Utilities' internal project management methodology which provides specific guidelines, procedures, work instructions, and industry best practices that allow the project work to be performed in an economically efficient, cost effective, and safe manner.

VI Investment Projects

The material investments from 2020 to 2024 that form the Transformer Renewal investments are included in Table A09 - 6.

Table A09 - 6: Material Projects and Initiatives

Project Code	Project Name	CAPEX ($MM)
101508	Transformer Renewal	$34.0

Appendix A10 - Underground Asset Renewal

I Overview

Alectra Utilities' planned Underground Asset Renewal investments consist of multi-year and single-year projects to replace three categories of underground assets that are leading to increasingly poor reliability for many customers. Through these investments, Alectra Utilities expects to replace assets that are at the end of their useful life, and return service levels to those affected customers to within acceptable levels of reliability by mitigating the increasing risk that customers will experience prolonged and persistent outages due to the deteriorating infrastructure.

The main categories of assets that will be replaced through these investments over the 2020-2024 period are:

- **Cable and Cable Accessories:** Cable and cable components that are at their end-of-life or in poor or very poor condition.
- **Switchgears:** Switchgear that are at their end-of-life or in poor or very poor condition.
- **Civil Structures:** Deteriorating structures that pose both a public and a worker safety risk.

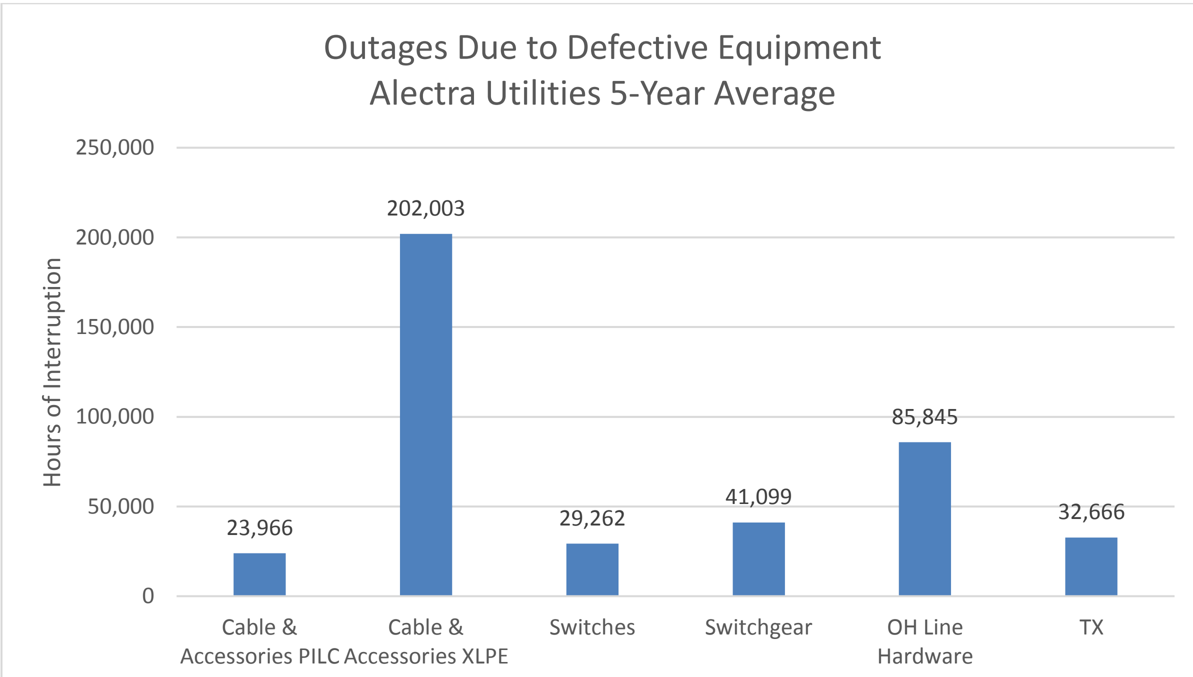
Table A10 - 1: Underground Asset Renewal Summary

	Historical Spending				Bridge	Forecast Spending				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$44.3	$43.3	$51.8	$43.6	$45.5	$61.1	$74.5	$82.2	$88.5	$95.5
Primary Driver:	Failure Risk									
Secondary Drivers:	Reliability, Functional Obsolescence, Safety									
Outcomes:	Improved Reliability, Improved Efficiency and Improved Safety									

Alectra Utilities' planned Underground Asset Renewal investments are driven by an increasing decline in reliability on the utility's distribution system. At present, defective equipment accounts for 45% of controllable outages in Alectra Utilities' system, and the majority of those outages are caused by failing cable, cable accessories and switching equipment. The collective failure of these assets contributes significantly to the declining reliability trend of Alectra Utilities' system, which is described in more detail in section 5.2.3 of the DSP – System Performance and Performance Trends.

Figure A10 - 1 illustrates the causes of all outages on Alectra Utilities' system that are due to failing equipment. Cable and cable accessory failures account for 54% of all equipment-related outages. Failing switches and switchgear account for a further 17% of all equipment-related outages.

Figure A10 - 1: Outages Due to Defective Equipment, Alectra Utilities 5-Year Average (2014-2018)



The proposed Underground Asset Renewal investments will address both asset groups, with a focus on mitigating outages due to failing direct-buried Cross-Linked Polyethylene ("XLPE") cable.[94] As described in detail below, outages due to cable failures are increasing despite the significant amount of historical spending to address the performance of these assets. Cables that

[94] The majority (97.7%) of underground conductors in Alectra Utilities' system is encased in Cross-Linked Polyethylene or Tree-resistant Cross-Linked Polyethylene (collectively, "XLPE"). Some sections of the system use older Paper Insulated Lead-Covered or "PILC" cable, in which wrapped paper is used to insulate the cable and molten lead used to cover splices in the cable.

have been stressed by previous faults will continue to degrade at increasing rates. Investment at the proposed level is urgently required to halt this decline and to restore reliability to historic levels.

The Underground Asset Renewal investments will also address degradation of reliability and safety risks due to failures of 25 kV air-insulated and oil-insulated switchgear and renewal of civil structures (manhole covers and vault lids) needed to mitigate public and worker safety issues. There is an urgent need to address these reliability and safety issues during the 2020-2024 DSP period.

The remainder of this evidence is organized around the three asset groups that will be addressed by the proposed investments:

- **Cables and Cable Accessories** (discussed in Section II),
- **Switchgear** (discussed in Section III), and
- **Civil structures** (discussed in Section IV).

For each asset group, Alectra Utilities describes the proposed investments, the drivers and need for the work, the proposed timing and pacing, and the alternatives considered by the utility.

II Cable and Accessories

2.1 Investment Description

This section summarizes the proposed investments to address deteriorating cable and cable accessories in Alectra Utilities' underground system. The specific drivers, need, and options considered to address these assets are set out in section 2.2, 2.3, and 2.4, respectively.

2.1.1 XLPE Cables

Alectra Utilities' service area currently contains an extensive population of underground cables totalling approximately 22 million linear meters of cable, which are continuing to degrade. Almost all of these cables are XLPE (either the first generation XLPE cable, or the subsequent tree-resistant XLPE cable).

Cable manufacturers introduced the first-generation XLPE cable into the market in the late 1960's. These cables have inherent problems due to the nature of the manufacturing processes, which led to impurities developing into electrical trees over time in the insulating medium. These impurities are responsible for the increase in cable failures that Alectra Utilities and the electrical utility industry has been experiencing with cables from this period.

The method of addressing XLPE cable failures is limited by the cable installation method. Decades ago, utilities buried cable directly in the ground. Over time, the construction standard shifted to installing cable in protective conduits, but much of the system still consists of "direct-buried" cable. When cable-in-conduit fails, it can typically be entirely removed and replaced with brand-new cable with relative ease. In contrast, direct-buried cables can only be repaired by excavating the cable and splicing in a replacement segment. This approach is fundamentally reactive and introduces further complications, since the installed splice may itself become a future failure point. Nor does it solve the underlying issue, since the older, direct-buried cable remains installed and increasingly likely to fail again.

The degradation of these assets is directly impacting customers. As a recent example, the York Hills and Hilda neighbourhood in Vaughan experienced increasing cable faults. In the summer of 2018, customers in this neighbourhood experienced eight outages over three weeks – an average of one outage every three days.[95] These outages were all caused by different failures to one segment of buried XLPE cable. Alectra Utilities repaired each fault reactively, only to experience another cable failure in the area several days later, resulting in increased customer frustration and dissatisfaction. It became clear that the cable was no longer dependable and needed to be replaced entirely. Emergency replacements like this are considerably more expensive than planned replacements as proposed in this DSP.

Figure A10 - 2: York Hilda Cable Trench

Figure A10 - 2 illustrates several challenges with direct buried XLPE cable installations. Firstly, the image reflects XLPE cables intertwined and in very close proximity, which causes cascading failures. In the York Hills and Hilda example above, a cable fault on one phase caused a failure of a cables of a different phase. For situations where bundled cables are causing cascading failures, Alectra Utilities must address this cascading failure risk by replacing direct-buried cable with cable segments in protective conduits.

[95] On two occasions, the underground system incurred multiple cable faults on different phases. In two instances, the same cable segment failed downstream from a recently completed cable repair.

During the 2020-2024 period, Alectra Utilities plans to increase its spending to rejuvenate or replace XLPE cable and related accessories that are either in poor or very poor condition.[96] As shown in Figure A10 - 2 above, these assets are the single largest equipment-related cause of outages in Alectra Utilities' distribution system. Failing direct-buried cables are causing an increasing number of outages, and when buried cables fail it can take a significant amount of time to restore service. Failing cables are significantly and increasingly impacting the quality of service received by Alectra Utilities' customers.

Alectra Utilities must increase spending to address the growing population of cables in poor and very poor condition now, or else it will face a potentially-overwhelming backlog of deteriorated cable in subsequent years. Alectra Utilities already faces a very large population of cables that need to be replaced immediately: 14% of Alectra Utilities' total cable population is in very poor and poor condition. The high volume of cables in very poor and poor condition already represents a significant backlog. Alectra Utilities plans to prioritize addressing a portion of this backlog during the five-year DSP period.

2.1.2 Two Options: Cable Rejuvenation and Cable Replacement

Alectra Utilities plans to address these cables through a combination of two renewal strategies: cable rejuvenation and cable replacement. For each project, Alectra Utilities will use the strategy that delivers the best value for customers.[97]

Option 1: Cable Rejuvenation

Cable rejuvenation is a lower-cost solution that can extend the life of XLPE cables by injecting a fluid into the core of a buried XLPE cable. The fluid combines with the existing insulation and increases the strength of the insulation and slows down the rate of further degradation. This approach economically allows cable life to be extended provided that the cable is eligible to receive this treatment, that is that the condition of the cables is salvageable and would benefit from having its life extended and secondly that the cable construction allows for the liquid to be

[96] Underground assets targeted for renewal have Health Index results of Very Poor or Poor, as identified by the Asset Condition Assessment (ACA) process. Detailed information on Alectra Utilities' ACA process is provided in DSP Section 5.3.3 and Appendix D - Asset Condition Assessment – 2018.
[97] A detailed explanation of the options Alectra Utilities considered when developing these investments is set out below in section 2.4.

received. It must be noted that this solution will also result in the cable eventually required to be replaced. However, in the interim, this method avoids the need to excavate and replace the entire cable, which is a more costly and significantly disruptive to customers and neighbourhoods.

Figure A10 - 3: Underground Cable Rehabilitation by Cable Injection

Where possible, Alectra Utilities will prioritize rejuvenation over replacement, since it is less expensive. However, not all cables are good candidates for rejuvenation. Cables that are in very poor condition or at their end-of-life cannot be rejuvenated; they are too far deteriorated and tend to fail even if they are rejuvenated. Alectra Utilities must also consider other factors about the cable that could affect the cost-efficiency of rejuvenation compared to a full replacement.[98]

As the population of cables deteriorates, Alectra Utilities increasingly loses the opportunity to rejuvenate current assets. A large population of Alectra Utilities' cables are quickly approaching either their end-of-life or very poor condition. If Alectra Utilities does not increase its investments to address these assets in the 2020 to 2024 period, its only option will be the outright replacement of those cables, resulting in significant impacts on reliability and ultimately higher costs for customers.

[98] Other factors relevant to selecting the right approach include type of cable (strand filled or solid core cable are not eligible for injection), the location of splices and proximity to each other, the number of splices within the cable segment, the location of cable (e.g., under a boulevard, under a sidewalk, under a roadway, under a driveway), and the actual field conditions (i.e. the ability to excavate and civil work cost required to replace the cable).

Option 2: Cable Replacement

In some cases, either because of the condition of the cable or other factors, Alectra Utilities has only one prudent choice which is to replace the cable. In these instances, Alectra Utilities will replace direct-buried cable with the new generation of XLPE cable, which will deliver superior reliability over their lifetimes relative to older standards of cable. The cable will also be installed in conduit which is a superior method of installation as compared to direct-buried cable. The conduit provides protection from mechanical and corrosive damage and will make future replacement much simpler.

Figure A10 - 4: Underground Cable Replacement

During an underground system rebuild project, Alectra Utilities reviews the layout of the distribution system to with the objective of optimizing the configuration and layout. For many areas, Alectra Utilities is able to reconfigure the layout to minimize the replacement cost. Table A10 - 2 summarizes the outcomes and benefits of the proposed cable and cable accessory investments.

Table A10 - 2: Cable and Accessories Investments Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Reliability	• Replacing or rejuvenating degraded underground cables will reduce the risk of future outages to customers. • The replacement of XLPE direct-buried cables with new cables in conduits introduces significant reliability benefits. The new XLPE cables are manufactured to the latest specifications and do not have the inherent historical flaws of older generation cable.
Efficiency	• Replacing direct-buried cable with cables in conduit creates future efficiencies. When the cable needs to be replaced in the future, the entire cable segment from device to device can be replaced rather than the costly process of crews locating the fault, and excavating a pit to install a splice in the cable.

2.2 Drivers

The primary driver of the proposed investments in underground cable and cable accessories is to address the significant risk of failure associated with these assets, since this is the issue that will be directly addressed by the proposed expenditures. The outcome of this driver is to reverse the declining the reliability due to failing cables, restoring reliability to historic levels.

The driver for this investment is further defined and summarized in Table A10 - 3.

Table A10 - 3: Cable and Accessories Drivers

Investment Driver	Reasoning and Investment Benefits
Driver: **Failure Risk**	The primary driver for these investments is the elevated risk of failure, leading to poorer reliability for Alectra Utilities' customers. The increased risk of failure is primarily driven by the deterioration of the insulating material and associated equipment elevated risk of failure associated with the cable and cable accessories addressed in these investments. Alectra Utilities expects that the reliability of the underground distribution will improve as a result of the planned cable and cable accessory renewal investments.
Reliability	Replacing or rejuvenating degraded underground cables will reduce the risk of future outages to customers. The replacement of XLPE direct-buried cables with new cables in conduits introduces significant reliability benefits. The new XLPE cables are manufactured to the latest specifications and do not have the inherent historical flaws of older generation cable.

2.3 Need

This section provides further detail of the impact that the identified cable and cable accessories are having on Alectra Utilities' underground distribution system, as well as the condition of the assets to be replaced.

Table A10 - 4: Cable and Cable Accessories Summary

	Historical Spending				Bridge	Forecast Spending				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$38.6	$36.4	$46.5	$40.8	$34.6	$48.0	$61.1	$68.3	$74.2	$81.0
Primary Driver:	Failure Risk									
Secondary Drivers:	Reliability									
Outcomes:	Improved Reliability and Improved Efficiency									

Increased Expenditures Needed to Address Reliability

As shown in Figure A10 - 1 above, failing cables and cable accessories are the leading cause of equipment related outages on Alectra Utilities' distribution system. Over 90% of these outages result from the failure or XLPE cable.

Outages due to failing XLPE cable have increased by 30% from 2014, or 8% per year, as shown in Figure A10 - 5. When buried cables fail, it can take a significant amount of time to identify, excavate and address the fault, resulting in longer outages for customers. This is reflected in Figure A10 - 6, which shows that the length of outages due to failing XLPE cable has increased by 31% since 2014, an 8% per year increase. This decreasing reliability has greatly impacted Alectra Utilities' reliability and the satisfaction of its customers.

Figure A10 - 5: Number of XLPE and XLPE Accessories Failures per Year (2014-2018)

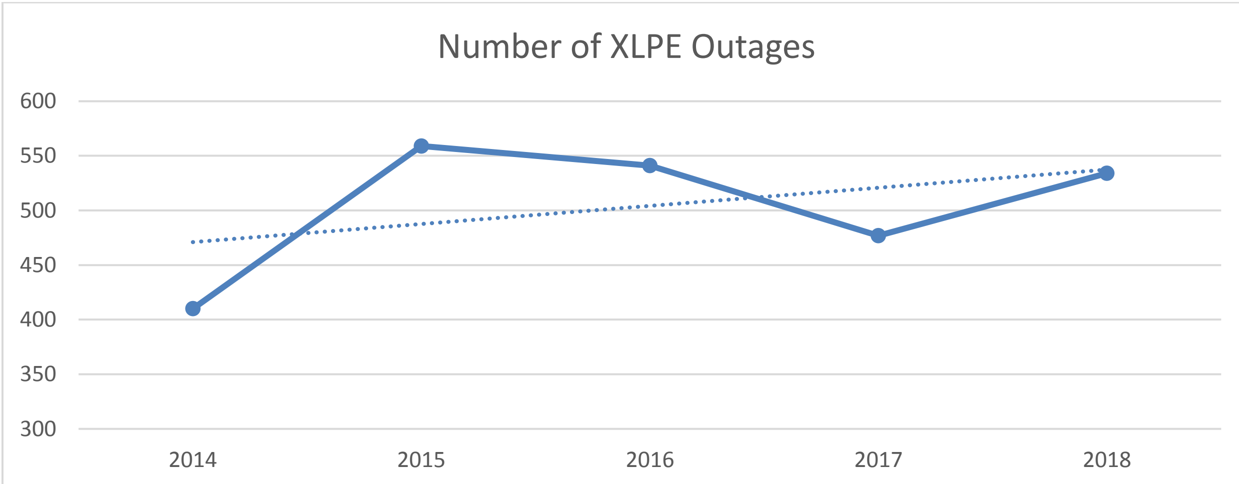
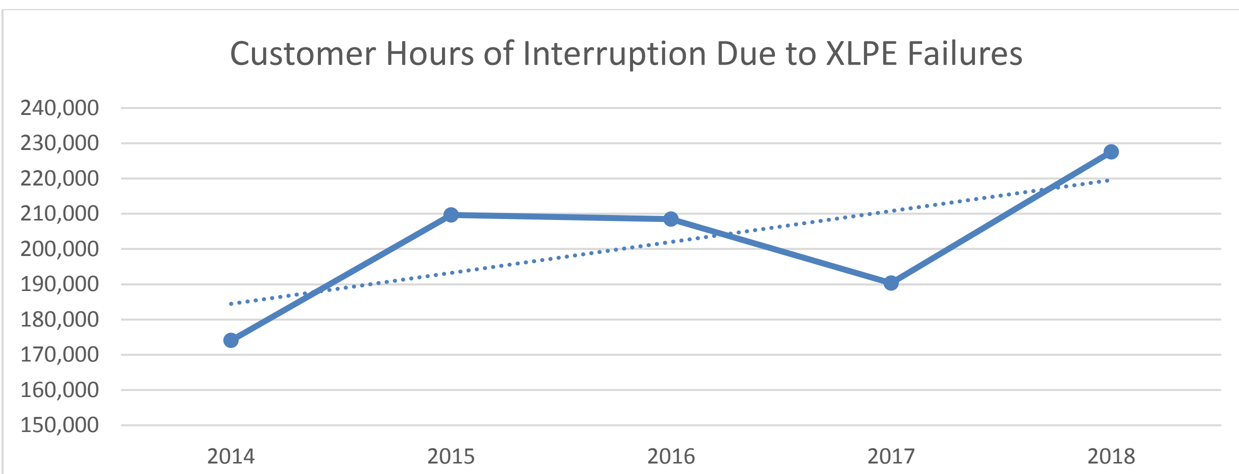


Figure A10 - 6: Customer Hours of Interruption per Year from XLPE and Accessory Failures (2014-2018)



Although Alectra Utilities has attempted to address these trends within its existing funding, past expenditures have not been sufficient to stop the declining performance of the assets, let alone restore reliability to historic levels. Alectra Utilities has increasingly been required to address underground cable failures on a retroactive basis. In the 2018 example from the York Hills and Hilda neighbourhood discussed above, unplanned outages occurred that forced Alectra Utilities to spend an additional $3.7MM on cable replacement to manage almost weekly cable failures.

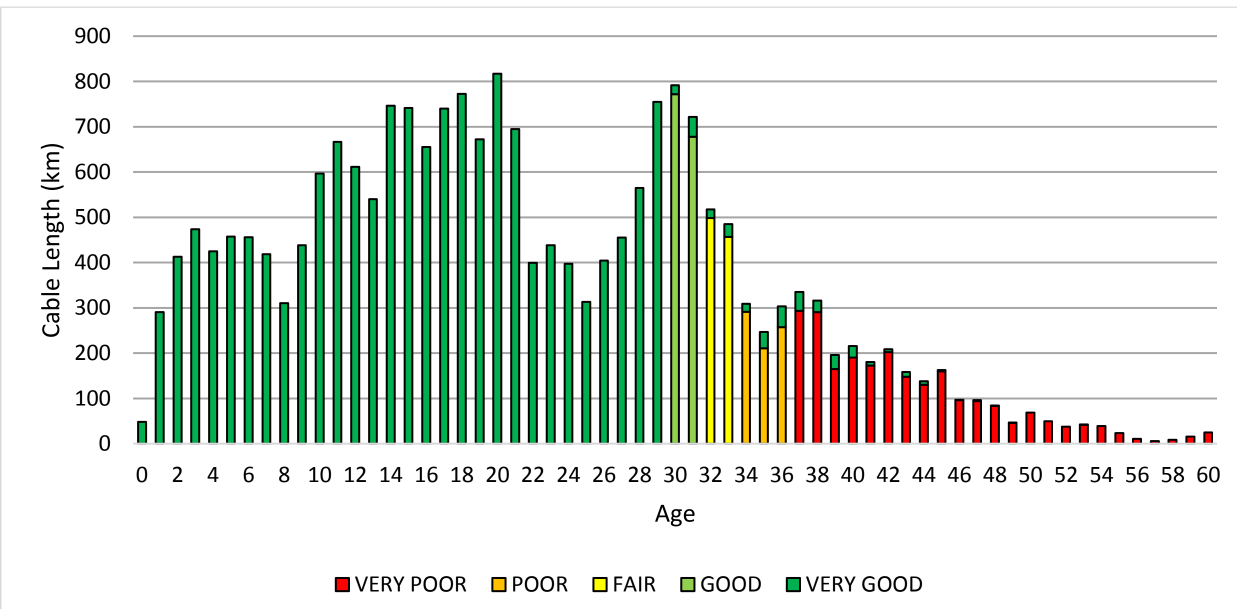
Alectra Utilities urgently needs to increase spending not only to halt the increasing trend, but also to reverse it and reduce the number of cable failures to return customers back to historical reliability levels. Without the proposed expenditures, cables will continue to degrade and Alectra Utilities expects reliability to decline further as deteriorated cables begin to fail at greater rates, having been stressed from historical faults.

Increased Expenditures Needed to Address Aging Cable Population

In addition to the significant amount of cable that is currently in very poor condition, Alectra Utilities must also plan to address a wave of cable that will deteriorate in the coming years.

As illustrated in Figure A10 - 7, there is a direct correlation between the age and condition of XLPE cable.[99]

Figure A10 - 7: XLPE Cable by Condition

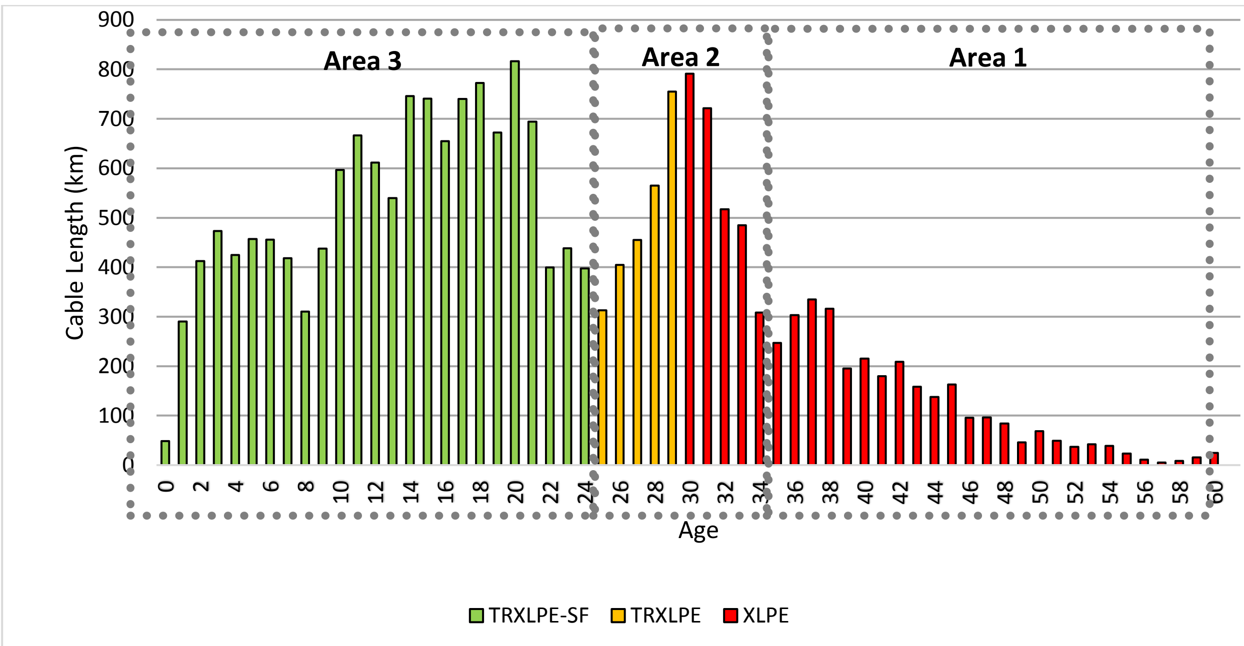


The proposed investments focus on Area 1 and Area 2 as shown in Figure A10 - 8. All of the cable in Area 1 is in very poor condition and cannot be rejuvenated. Most of the planned cable replacement expenditures target this group of cable. The cables in Area 2 are in a range of conditions, but they will quickly slide into very poor condition if not addressed in the near term.

[99] Health Index for cables are based cable type (including installation) and cable age. For example, Non-Tree Retardant XLPE direct buried cable has a different failure curve then Tree Retardant XLPE cable in a conduit.

Alectra Utilities plans to rejuvenate eligible cables in this area before it deteriorates further. The cable in Area 3 does not need proactive investment during the term of this DSP.

Figure A10 - 8: XLPE Cable by Type



Asset Description by Area

This section describes the assets in each area shown in Figure A10 - 8 including the strategies that Alectra Utilities may use to address failing and deteriorating cable in each area.

Area 1

Area 1 consists of first generation XLPE cables. Due to the technology and capability of the manufacturing processes available at the time for these cables, impurities were able to enter the insulating medium. As such, these cables possess a far greater susceptibility to water and electrical “treeing,” which will ultimately result in partial discharge and eventual failure of the cable. The majority of these cables are also direct-buried (i.e. not installed in conduits) which is an aggravating condition to the rate of degradation of the cables. Also unlike failed cables-in-conduit, which can typically be removed and replaced with new cable segments, failed direct-buried cables can only be excavated and repaired via cable splicing in a reactive situation. As noted above, the installed splice may also introduce a future failure point.

These cables have also been in-service longest, and have therefore seen more faults and normally had more failures (and consequently, more repairs) than younger cable. These cables do not tend to be materially improved by rejuvenation. In addition, the cost of rejuvenation increases based on the number of splices that need to be replaced. This limits the cost effectiveness in comparison to replacement to the point where the better value is to replace the cable.

Cable accessories in this area are also of first-generation construction and would be replaced along with the cable.[100]

Area 2

The cable in Area 2 is predominantly first generation XLPE cables that for the majority are direct buried. However, based on their younger age and fewer lifetime repairs, some of these cables are candidates for rejuvenation.

Not all of the cables in Area 2 can be rejuvenated, either due to the conductor used in the cables or the number of repairs that a specific cable has incurred over its lifetime.[101] Alectra Utilities will endeavour to maximise the amount of injectable cables in this segment to reduce the magnitude of cable replacement until the older segments in Area 1 can be managed.

Cable accessories in Area 2 are mixed. Some accessories are similar to Area 1, while other are of newer design which have eliminated the deficiencies of the earlier versions.[102]

Area 3

Cables in Area 3 are in very good condition and are not being considered for investment in this DSP. However, Alectra Utilities notes that many of the cables in this area are “strand-filled” and therefore not eligible for rejuvenation. When these cables begin to

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[100] For example, elbows on the 27.6kV system are “non-vented,” which have led to a partial vacuum flashover when operated. Splices are heat shrink or first-generation cold shrink. Terminations may be hand taped (not manufactured) which degrade faster than a cold shrink body.

[101] Solid conductor style cables cannot be injected. Similarly cables that are strand filled cannot be injected. These were used by Alectra Utilities legacy utilities however, the data currently available makes it extremely difficult to determine to what extent this reduces the amount of injectable candidates.

[102] Splices, elbows, and in some cases, terminations would have to be replaced during the injection process as the fluid cannot flow through the legacy devices.

deteriorate, Alectra Utilities will have no option but to replace them. However, since most of these cables are in conduit, the replacement will be less expensive than for older cables. A secondary benefit includes the installation on newer generation strand filled cable which is expected to have a longer operating life than earlier generation cable.

Similar to Area 1 and Area 2 cable accessories are also replaced this is because the components are not reusable and therefore must be replaced.

2.4 Options Analysis

Alectra Utilities has considered three different investment strategies to manage the aging and deteriorating underground cable infrastructure within its service area. These include the following:

- Strategy 1: Accelerated pace (Improve cable reliability by 8%)
- Strategy 2: Moderate pace (Maintain cable reliability at 2018 level)
- Strategy 3: Reduced pace (Allow cable reliability to worsen by 10%)

The expenditures proposed reflect Strategy 1: investing at an accelerated pace.

In the second phase of customer engagement, Alectra Utilities received strong support for underground system renewal; 73% of residential customers that participated in the second phase of customer engagement indicated support for the recommended or accelerated pace of the renewal. Preference to proceed with underground renewal investments was also received from business customers (65% of small business, 97 of 137 mid-sized business and 10 of 13 large users) prefer the recommended or accelerate pace. Based on the need of investment and strong customer preference for underground system renewal, Alectra Utilities has incorporated into plans the accelerated pace for underground cable renewal. Alectra Utilities must address the cables in Area 1 and Area 2 now to be prepared for the wave of cables in Area 3 shown in Figure A10 - 8. If Alectra Utilities does not deal with Areas 1 and 2 now, then it will have no ability to manage the larger volume of assets in Area 3.

<u>Strategy 1: Accelerated pace (Improve reliability by 8%):</u>

Strategy 1 would address all cables in Areas 1 and 2 by 2028. Figure A10 - 9 illustrates the overall breakdown of cables identified for intervention under this strategy between cable replacement and rejuvenation respectively.

Figure A10 - 9: Cables Identified for Injection or Replacement under Strategy 1 (km)

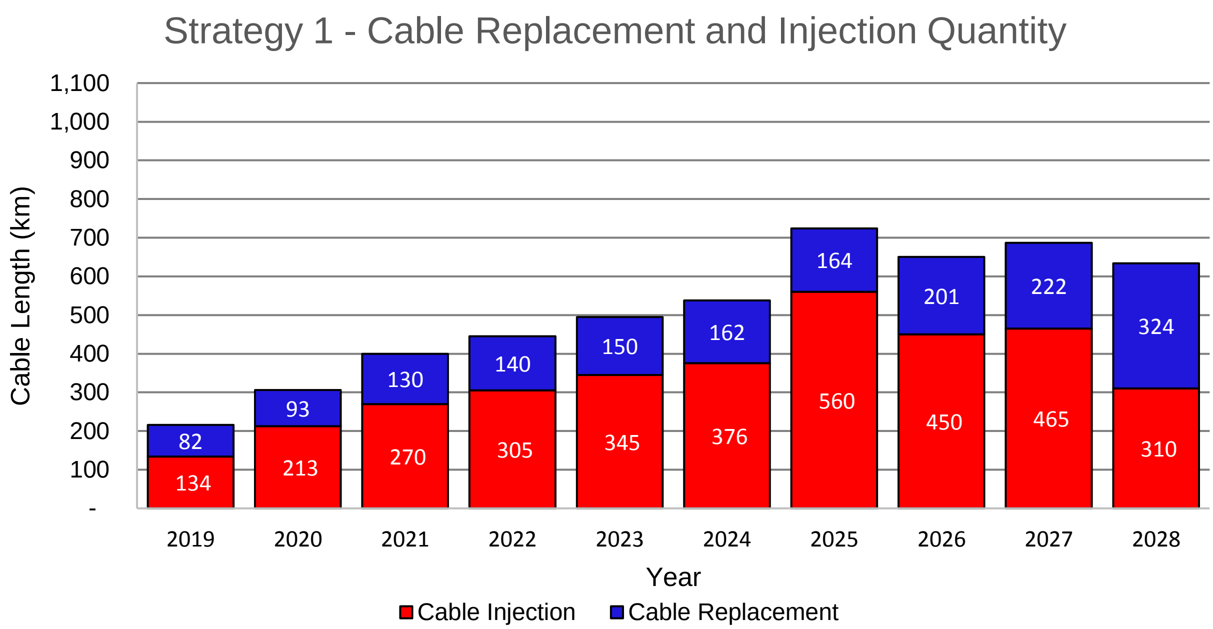
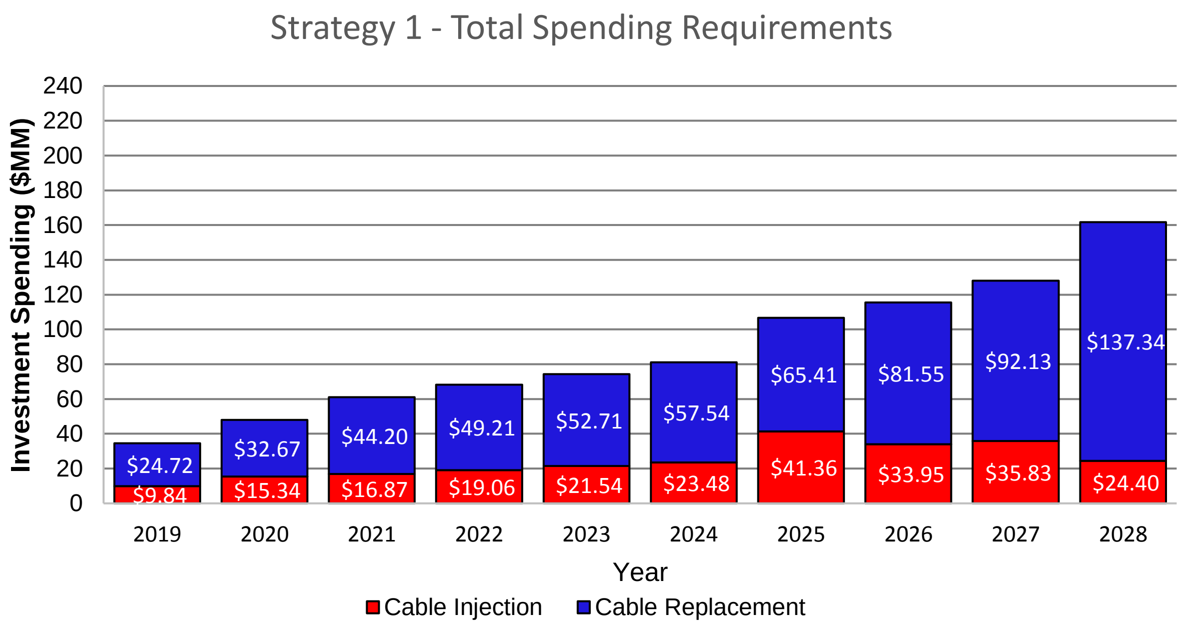


Figure A10 - 10 illustrates the total spending that is associated with Strategy 1. Total investments over the five-year DSP period would exceed $332MM, which would have the greatest impact to customers in terms of rates. Furthermore, long term sustainment based on asset condition assessment suggest that we move forward with the accelerated pacing of underground renewal as this provides the highest value to customers over the next 20 years. In making the recommendation, Alectra Utilities considered customers priorities to maintain rates and hence recommended the moderate pacing. In the second round of customer engagement, 73% of residential customers and 65% of small business customers indicated strong support for either the recommended or accelerated pacing. Due to the need of the investment, the value of the renewal and strong customer support, Alectra Utilities adjusted the underground investment to accelerate the pacing for renewal of underground assets.

Figure A10 - 10: Strategy 1 Total Spending Requirements



Strategy 2: Moderate pace (Maintain reliability at 2018 level)

Strategy 2 addresses some of cables in Areas 1 and 2 in the DSP period at a pace which keeps the predicted failure rate in line with the 2015-2018 average failure rate (528 failures per year), thus maintaining reliability at the 2018 level (534 failures). Figure A10 - 11 illustrates the cable replacement and injection quantities under this scenario.

Figure A10 - 11: Cables Identified for Injection or Replacement under Strategy 2 (km)

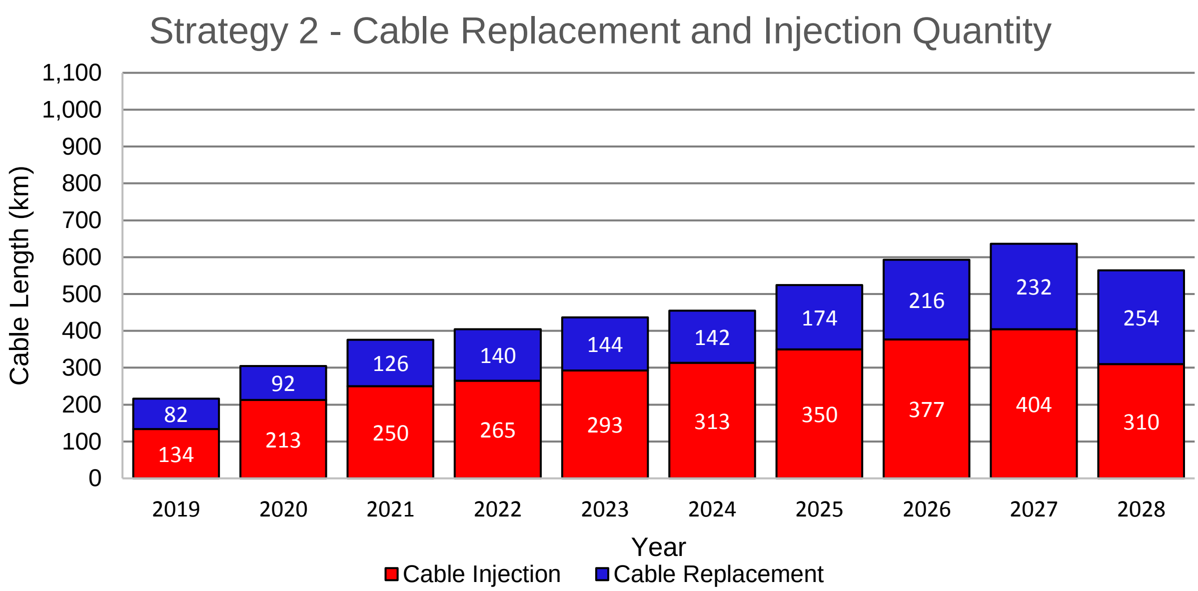
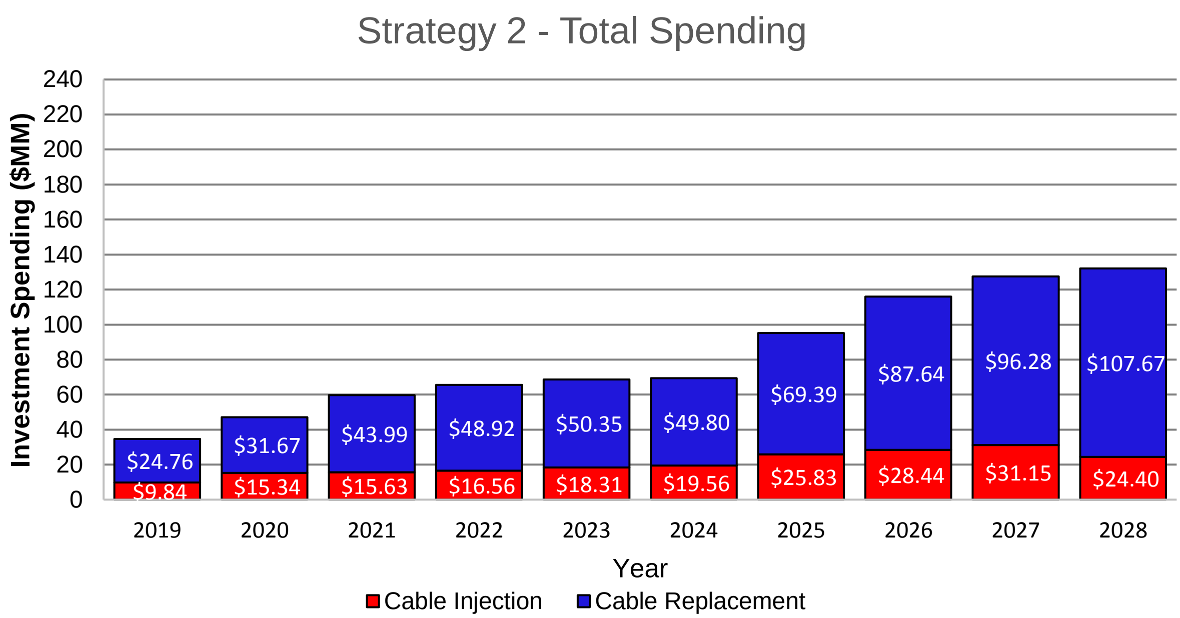


Figure A10 - 12 illustrates the total spending that is associated with Strategy 2. Total investments over the five-year DSP period would amount to $310MM. These activities are expected to address 56% of the population leaving another 3,526 km in Areas 1 and 2. The downside of this strategy is failure rates are already higher than those experience in 2014, and this strategy would not return reliability to 2014 levels.

Figure A10 - 12: Strategy 2 Total Spending Requirements



<u>Strategy 3: Reduced pace (Allow reliability to worsen by 10%)</u>

Strategy 3 addresses some of cables in Areas 1 and 2 in the DSP period by 2028. Figure A10 - 13 illustrates the overall breakdown of cables identified for intervention under this strategy between cable replacement and injection respectively.

Figure A10 - 13: Cables Identified for Injection or Replacement under Strategy 3 (km)

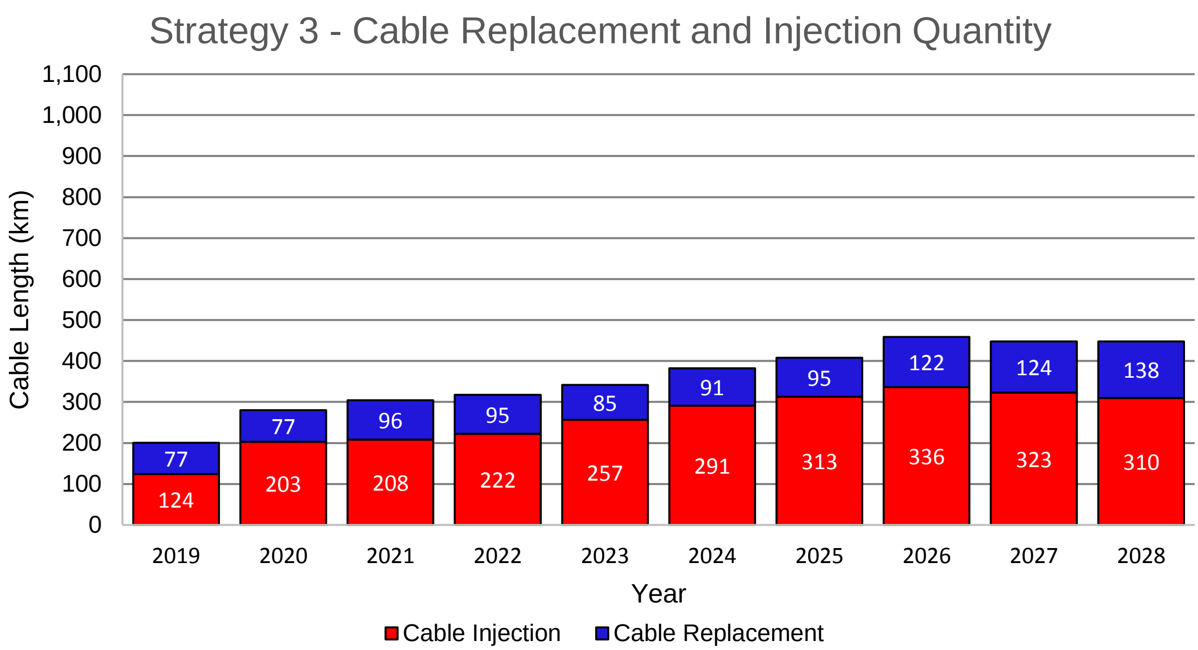
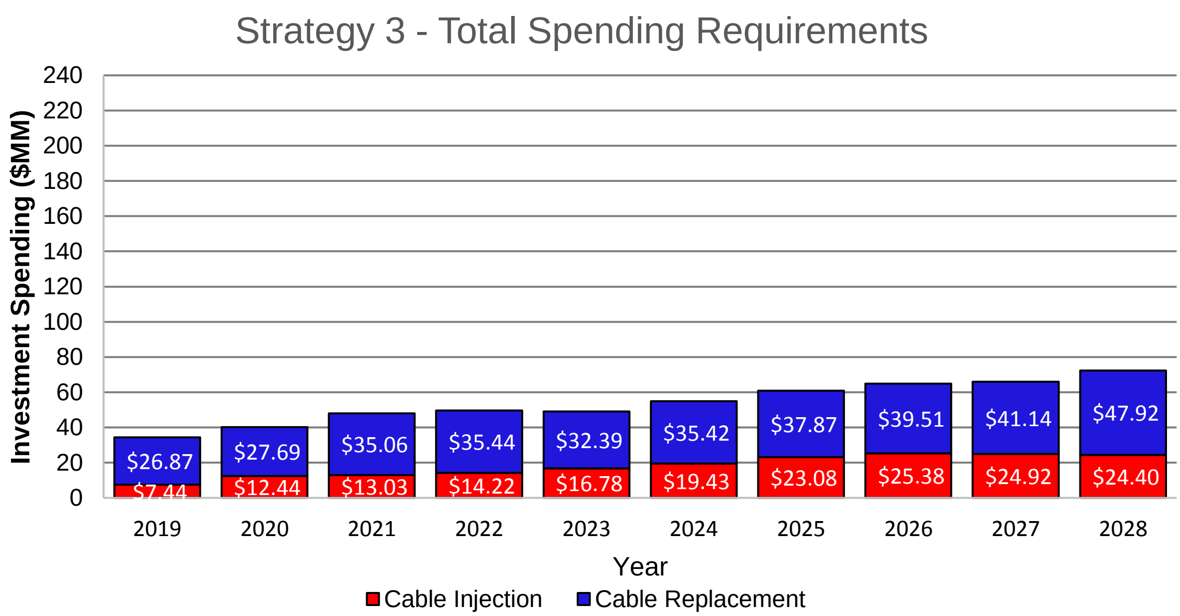


Figure A10 - 14 illustrates the total spending that is associated with Strategy 3. Total investments over the five-year DSP period would amount to $242MM. These activities are expected to address 44.7% of the population leaving another 4,448 km in Areas 1 and 2. This pace would continue to worsen reliability above the 2018 level by approximately 10%. However, this strategy would result in no rate increases.

Figure A10 - 14: Strategy 3 Total Spending Requirements



Summary of Cable and Cable Accessory Investment

Alectra Utilities has determined to pace expenditures for Cable and Cable Accessories at the accelerated investment level shown in Strategy 1. At this rate the bulk of the investment in Underground Asset Renewal is direct investment into Cables residing in Area 1 and Area 2 and accounts for 83% of the forecasted spend from 2020-2024. This is not unreasonable but could be insufficient based on three major factors. The amount of cable which needs to be addressed is increasing at a rate faster than can be managed at the current levels of investment. The accelerated investment level marginally improves reliability beyond the 2018 level but does not return the level of reliability to the five year average. Additionally, the amount of time and resources required to reactive or proactively deal with cable failures is significantly more than those required to deal with other asset failures. If cable and cable accessories are not proactively addressed within this DSP, it will be extremely difficult or impossible to manage the volume of cable requiring intervention.

The proposed investments do not address other categories of cables that are also negatively affecting customer reliability, but to a lesser extent. Alectra Utilities' lower-voltage secondary distribution and service cables are another source of some reliability issues. A portion of Alectra Utilities' feeders use PILC cables that, while generally in good condition, are not immune to failure.

While work must be done to address these assets, typically on a reactive basis, Alectra Utilities believes proactive replacement can be deferred to allow for focus on the more pressing issues associated with the XLPE cables and cable accessories proposed by the Underground Asset Renewal investments in the 2020 to 2024 period.

III Switchgear

3.1 Investment Description

This section summarizes the proposed investments to address deteriorating switchgear in Alectra Utilities' underground system. The specific drivers, need, and options considered to address these assets are set out in section 3.2, 3.3, and 3.4, respectively.

3.1.1 Underground Switchgear in Alectra Utilities' Distribution System

Padmounted switchgears are a critical component of the underground distribution system. Underground distribution systems are based on large "trunk" feeder cables that are connected to smaller distribution cables that directly serve customers and neighbourhoods. The system relies on padmounted switchgear to connect local distribution circuits to the main feeder cable systems, and to interconnect multiple trunk feeder circuits. A single switchgear can impact as a many as 5,000 customers.[103]

Alectra Utilities has identified a significant need to increase its investment in replacing two groups of legacy switchgear that carry significant reliability and safety risks due to: condition, past design and installation practices. These two groups are (i) 25 kV air-insulated "live front" switchgear and (ii) oil-insulated switchgear. Alectra Utilities plans to replace all of the Poor and Very Poor air-insulated switchgear on the 27.6kV system as well as all the oil-insulated units in operation that are in Very Poor condition.

As shown in section 3.3 below, the failure of padmounted switchgears is materially contributing to decreasing reliability of service for customers served by Alectra Utilities' underground distribution system.

[103] Switchgear serve several other important functions in the underground distribution system. They are used to isolate sections of the system for maintenance, safety and other reasons. They allow Alectra Utilities to "sectionalize" the system, provide fusing for lateral connections, and to reconfigure cable loops for maintenance, restoration and other operating requirements.

3.1.2 Air-Insulated "Live-Front" Switchgear

Air-insulated switchgears utilize insulators and air as the means to insulate live components from ground. These units have been failing earlier than expected, due to a combination of usage and environmental factors.

The reported useful life of padmounted switchgear is 20-45 years with a typical useful life of 30 years when operating within a normal continuous rated operating voltage of 25kV.[104] Air-insulated switchgear use porcelain insulators and air to insulate live components from ground. These air-insulated switchgear 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 25 kV and tested to operate as high as 28 kV to ensure operation at 27.6 kV 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. However, as noted above, where these units have been installed on Alectra Utilities' 27.6 kV underground distribution system (which has a maximum range of 29.3 kV), they have experienced failures at service ages as low as 11 years.[105]

Environmental factors in southern Ontario have also led to earlier failure of these switchgear. While these units function relatively well when their environment remains dry, 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.

These switchgear use a "live front" design, in which energized components are exposed and accessible when the access doors are opened for inspection, maintenance or operation. This design means that crews must take additional safety precautions when working with this equipment. In addition, the increasing failure rate of these switchgear means that workers may

[104] Kinectrics Inc., "Asset Depreciation Study for Use by Electricity Distributors" (EB-2010-0178), July 8, 2010.
[105] The units were purchased at 25 kV as this was a standard American voltage and was all that the manufacturer offered. The maximum rating of 28 kV was above the 27.6 kV operational rating.

be at higher risk of being exposed to an arc flash. The planned replacement units would remove this risk.

Alectra Utilities plans to replace its 25 kV air-insulated switchgear with solid di-electric switchgear rated at 35 kV. This approach will achieve several benefits, including:

- Reducing incidences of failures due to flashover;
- Improved reliability;
- Better long-term value, as the replacement units have an expected useful life of 50 years; and
- Reduce maintenance and spare inventory cost.

3.1.3 Oil-Insulated Switchgear

Alectra Utilities also has a significant population of oil-insulated switchgear in its underground distribution system. As the name suggests, these units are filled with mineral oil, which operates as the switchgear's insulating medium – a typical oil-filled switchgear unit contains over 1,500 litres of oil.

When these units fail, the oil within them can ignite and cause a fire, creating a public and worker safety risk. Figure A10 - 15 shows the result of a typical failure of an oil-filled switchgear. As shown, many of these units are installed in public places and adjacent to customers' homes. Although the switchgears' oil tanks are sealed, any contamination of the oil (which occurs over time) will 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 (as was the case in the incident shown in Figure A10 - 15).

Figure A10 - 15: Failed Oil-Filled Switchgear, August 2018

3.1.4 Planned Investments

The switchgear units described above are a significant issue for Alectra Utilities and must be replaced proactively during the term of the DSP. The planned investments will replace 415 of these switchgear units across the system with a total cost of $39.3MM during the DSP period.

Table A10 - 5 summarizes the outcomes and benefits of the Underground Asset Renewal investments.

Table A10 - 5: Switchgear Investments Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Reliability	• The increased level of switchgear replacement is address customer outage levels associated with switchgear failures. • Certain replacement switchgear will be SCADA-enabled and/or fully automated, which allows for isolation, sectionalizing and restoration activities to take place in a substantially expedited manner.
Efficiency	• The new dielectric padmounted switchgear that will be installed as part of this investment do not require CO_2-cleaning maintenance practices.
Safety	• Replacement of legacy air-insulated padmounted switchgear with new dielectric switchgear introduce a number of safety benefits for field crews, as these new switchgears are self-contained and have minimal maintenance costs. • If the new switchgear are SCADA-enabled, they can be controlled directly from the control room and remove direct personnel operating the devices.
Environment	• In the case of oil-filled pad mounted and vault-mounted switchgear, catastrophic failure of these assets can result in a rupture, creating environmental impacts from leaking oil.

3.2 Drivers

The primary driver of the proposed investments in switchgear is to address the significant risk of failure associated with these assets, since this is the issue that will be directly addressed by the proposed expenditures. Secondary (but no less important) drivers are addressing the reliability impact these assets are having on customers, the functional obsolescence of legacy switchgear, and public and worker safety due to the failure risks posed by legacy switchgear.

The primary and secondary drivers are further defined and summarized in Table A10 - 6.

Table A10 - 6: Switchgear Drivers

Investment Driver	Reasoning and Investment Benefits
Primary Driver: Failure Risk	The primary driver for these investments is the elevated risk of failure, affecting public and worker safety and leading to poorer reliability for Alectra Utilities' customers. The increased risk of failure is primarily driven by the elevated frequency of failure associated with specific legacy switchgear addressed by these investments.
Secondary Driver: Reliability	Alectra Utilities expects that the reliability of the underground distribution system will improve as a result of the planned switchgear investments. In particular, Alectra Utilities expects that replacing existing legacy switchgears will improve reliability.
Secondary Driver: Functional Obsolescence	Obsolete asset types, such as porcelain insulators and non-load-break air-break switchgear, will also be replaced through these efforts. Replacement of these assets is expected to improve reliability and reduce rehabilitation and maintenance costs associated with maintaining these legacy assets.
Secondary Driver: Safety	By replacing legacy switchgear assets, the arc flash exposure risks currently facing workers will be mitigated, as will the worker and public safety risk posed by failure of oil-filled switchgear. Remote operation capability introduced by some replacement switchgear will remove the safety risk of live operations at the equipment.
Secondary Driver: Environment	By replacing oil-filled switchgear assets in poor condition, Alectra Utilities will mitigate the environmental risk posed by these legacy switchgear assets.

3.3 Need

This section provides further detail of the impact that legacy switchgear are having on Alectra Utilities' underground distribution system, as well as the condition of the assets to be replaced.

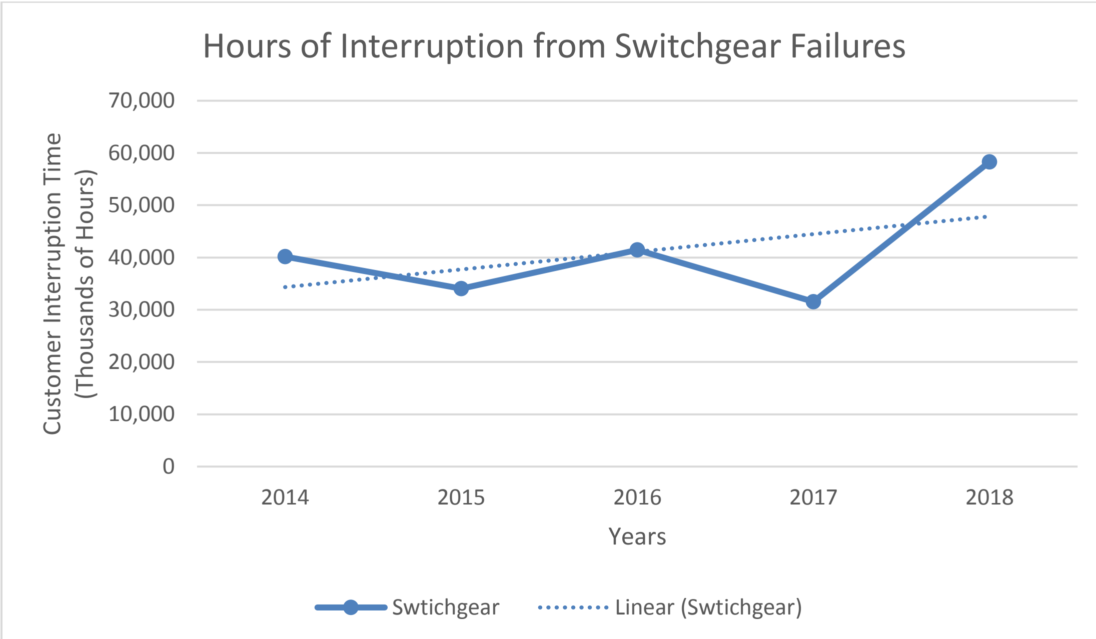
Table A10 - 7: Switchgear Summary

	Historical Spending				Bridge	Forecast Spending				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$3.8	$5.4	$4.0	$2.5	$5.8	$7.4	$7.6	$7.9	$8.1	$8.3
Primary Driver:	Failure Risk									
Secondary Drivers:	Reliability, Functional Obsolescence, Safety and Environmental risks									
Outcomes:	Better Reliability, Expedient Fault Finding and Restoration, Safety and Environmental Risk Mitigation									

Reliability Impacts of Legacy Switchgear

The failure of legacy switchgear is increasingly contributing to the duration of outages experienced by customers served by Alectra Utilities' underground distribution system. As shown in Figure A10 - 16, the hours of customer interruption resulting from failure of these assets has increased by 45% since 2014, and is primarily driven by the deteriorating condition of Alectra Utilities' switchgear assets.

Figure A10 - 16: Customer Hours of Interruption from Switchgear Failures (2014-2018)

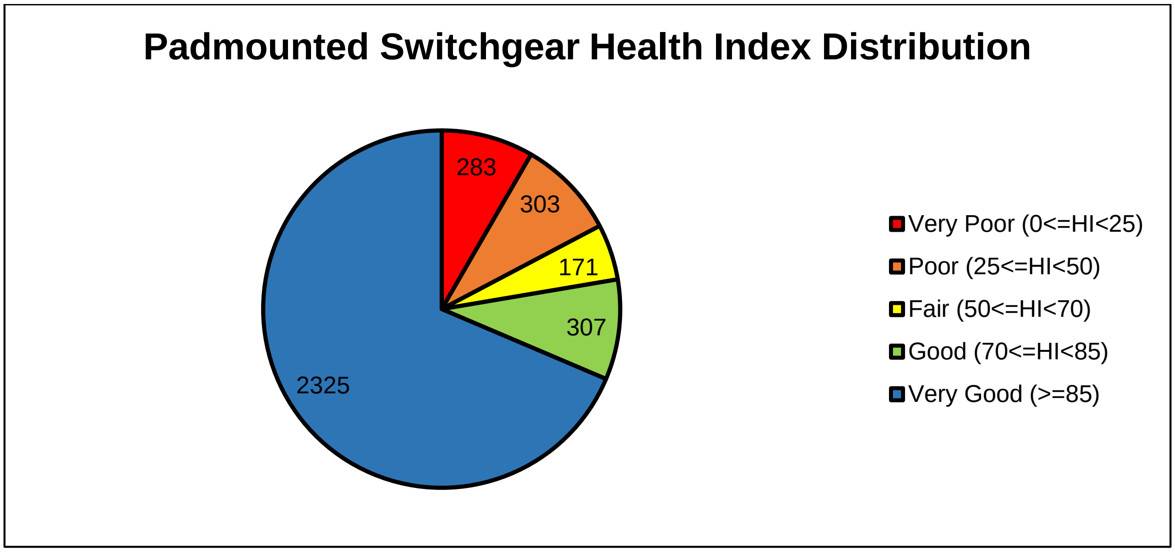


If the switchgear identified in the proposed investments are not addressed during the term of the DSP, Alectra Utilities expects that the reliability of the underground system will continue to worsen. If the proposed investments are delayed, Alectra Utilities expects that a significant backlog of switchgear replacements will develop, which will require significant investment and resources to correct (if possible).

Switchgear Population Condition

The HI values produced by Alectra Utilities' 2018 ACA pinpoint specific forms of degradation in distribution assets. As shown in Figure A10 - 17, 8.4% of Alectra Utilities' switchgear population is in Very Poor condition, 8.9% in Poor condition and 5% in Fair condition. Please see Section 5.3.3 or Appendix D - Asset Condition Assessment – 2018 for further information on the ACA and Alectra Utilities' asset management practices.

1 **Figure A10 - 17: Padmounted Switchgear Condition**

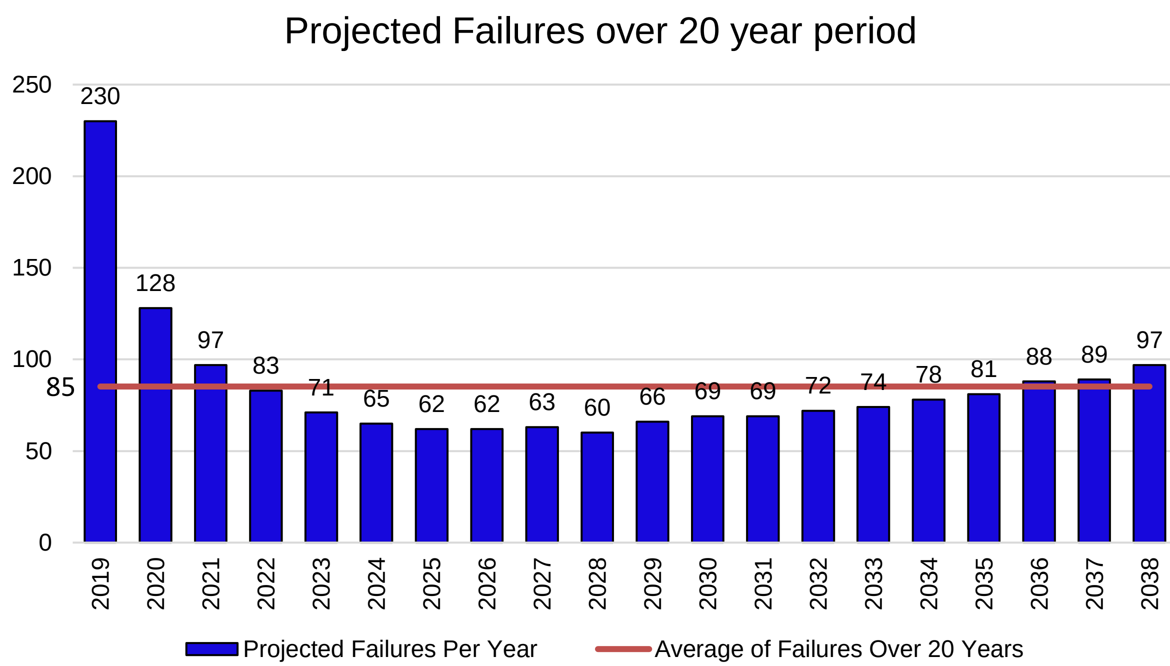


2

3

4 Figure A10 - 18 shows the projected failures based on current switchgear demographics under a
5 no planned investment scenario. Over the next 20 years, Alectra Utilities projects that 85 units
6 will fail annually, on average. This is above the current 5 year average based on reliability statistics
7 from 2014-2018.

Figure A10 - 18: Projected Failures over next 20 years



Switchgear Classes Addressed by Proposed Investments

Air-Insulated Live Front Switchgear

Air-insulated switchgear use porcelain insulators and air to insulate live components from ground. These air-insulated switchgear 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 25 kV and tested to operate as high as 28 kV to ensure operation at 27.6 kV 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. However, as noted above, where these units have been installed on Alectra

Utilities' 27.6 kV underground distribution system (which has a maximum range of 29.3 kV), they have experienced failures at service ages as low as 11 years.[106]

Alectra Utilities' air-insulated switchgears are also deteriorating due to their operating environment. These units function relatively well when their environment remains dry. However, the southern Ontario environment includes periods of high humidity and condensation from changing temperatures. As a result, Alectra Utilities' switchgears are regularly exposed to moisture that is mixed with dirt and road dust, which contributes 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.

As noted above, the "live front" design of Alectra Utilities' air-insulated switchgear units also poses potential safety risks to utility personnel. The design of these units exposes energized components when the access doors are opened for inspection, maintenance or operation. This introduces arc flash specification requirements and with the increasing frequency of failures due to flashover, workers are potentially exposed to a higher probability of an arc flash. Figure A10 - 19 and Figure A10 - 20 provide images of common component failures on air switchgear.

These units experienced a manufacturer defect with the stored energy spring mechanism used to operate the load breaking switch positions. While replacement parts are provided from the manufacturer, this added nuisance poses incremental risk and can nonetheless affect the safe operation of the units and Alectra Utilities' ability to provide reliable service to customers. Some of the units in service have been retrofitted with new spring units however, springs continue to fail and need replacement.

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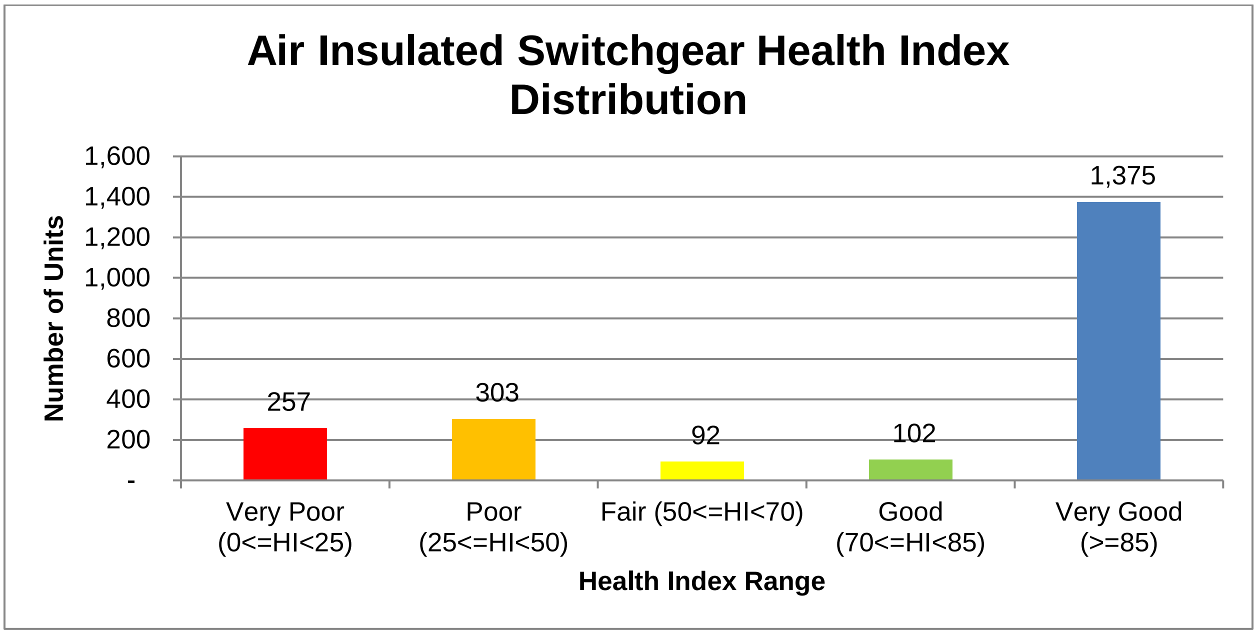
[106] The units were purchased at 25 kV as this was a standard American voltage and was all that the manufacturer offered. The maximum rating of 28 kV was above the 27.6 kV operational rating.

Figure A10 - 19: **Failed Insulator on Air switchgear**	**Figure A10 - 20:** **Failed Switch Mechanism**
	

Alectra Utilities and its predecessor utilities have previously attempted to mitigate air-insulated switchgear failures through regular inspection and dry ice cleaning of insulating components. While dry ice cleaning is effective over the short term, the problem remains persistent and the cost to perform dry ice cleaning is significant when considered over time.

Figure A10 - 21 provides the Health Index for air switchgear. Out of this population, 560 units are in either Poor or Very Poor condition, and require immediate attention. The majority of failed switchgear are from these deteriorated units. It is necessary to replace these units in very poor and poor condition throughout the 27.6 kV underground distribution system. Alectra Utilities expects that this investment will reduce the number and duration of outages and eventually allow for a reduction in O&M costs with a lower amount of dry ice cleaning.

Figure A10 - 21: Air Switchgear Health Index



Oil-Filled Switchgear

During the DSP period, Alectra Utilities needs to address a small but still significant population of oil-filled switchgear that are in very poor condition and present risks to safety, reliability, and the environment. Figure A10 - 22 shows a typical oil filled switchgear, post-failure. As described above, failure of these units creates both safety and environmental risks. In addition to the inherent importance of mitigating environmental risks, oil leaks add to the cost of replacement and increase the duration to restore power as the site needs to be remediated first.

Figure A10 - 22: Failed Oil Filled Padmounted Switchgear

Figure A10 - 23 provides the HI for oil-filled switchgear on Alectra Utilities' underground system. As shown, 18 units are in very poor condition and require immediate action.

Alectra Utilities is verifying whether any of these units may contain polychlorinated biphenyls (PCBs). Based on the results of this analysis, Alectra Utilities may need to replace some of the units in 'Fair' or 'Very Good' condition to reduce the risk of environmental and public safety concerns.

The population of in-service oil-filled padmounted switchgears totals 480. The age distribution of these units is illustrated in Figure A10 - 24. Based on the regulations regarding the use of PCB's, mineral insulating oil used in the period prior to 1984 has a higher probability of containing PCB's in concentrations > than 50 ppm. After 1984, PCB concentrations range anywhere from 2 ppm to <50 ppm. Oil-filled switchgears contain approximately 1300 litres of oil and catastrophic failure of these units can result in fire, personal injury, environmental contamination and property damage.

Local distribution companies in Ontario are governed by environmental legislation and regulations including the Ontario *Environmental Protection Act*[107] and the *Canadian Environmental Protection Act*.[108] This legislation governs the management of oil spills occurring from any in-service oil filled asset. These regulations prescribe end-of-use dates for equipment containing PCBs. The regulations under the Ontario *Environmental Protection Act*, require Alectra Utilities to report all spills of 100 litres or more of oil into the environment. In those instances, Alectra Utilities is required to make immediate arrangements for remediation of the site where the oil leak occurred. The regulations under the *Canadian Environmental Protection Act* require Alectra Utilities to report any spills involving more than one gram of PCB contaminating the environment. Under this scenario, Alectra Utilities is required to carry out full environmental remediation of the site where the oil leak occurred.

In order to maintain a high level of environmental stewardship and to ensure compliance with regulatory and environmental regulations, Alectra Utilities is required to urgently address situations where oil filled switchgear have been found to be leaking or containing PCB oil. To avoid expensive and hazardous environmental contamination and the need for subsequent remediation, Alectra Utilities has implemented a coordinated, paced and predictive replacement

[107] RSO 1990; O. Reg. 675/98.
[108] PCB Regulations: SOR/2008-273.

of known oil-filled switchgear. Units with PCB concentrations above 2ppm and leaking will be prioritized over units that are leaking but have PCB concentrations of less than 2 ppm.

Figure A10 - 23: Oil Switchgear Health Index

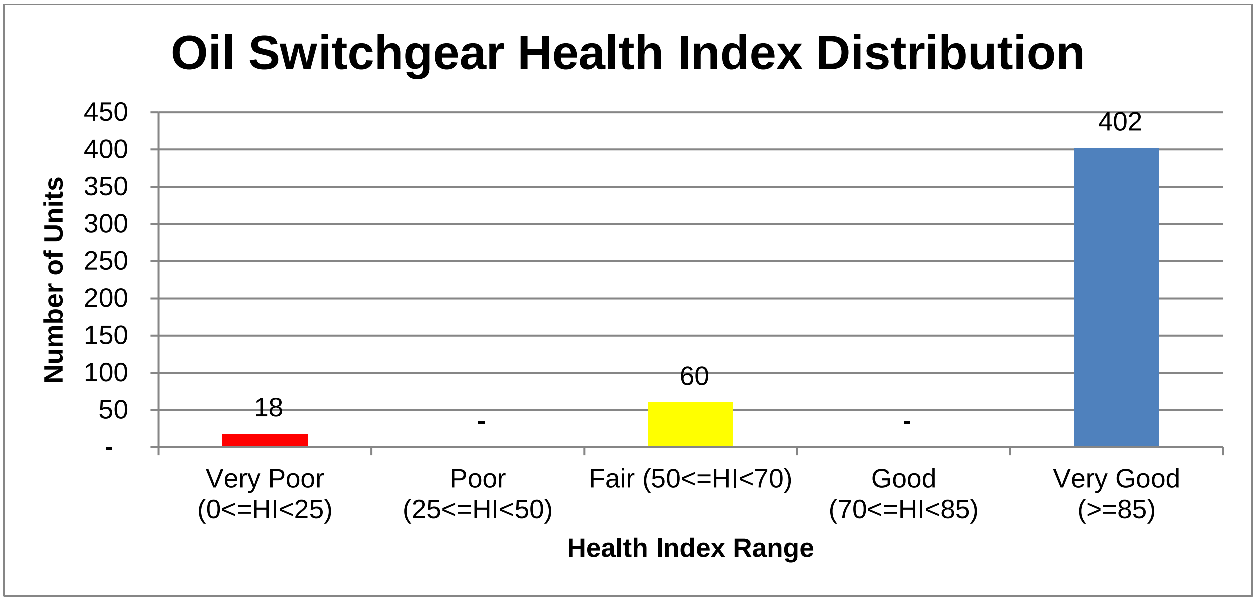
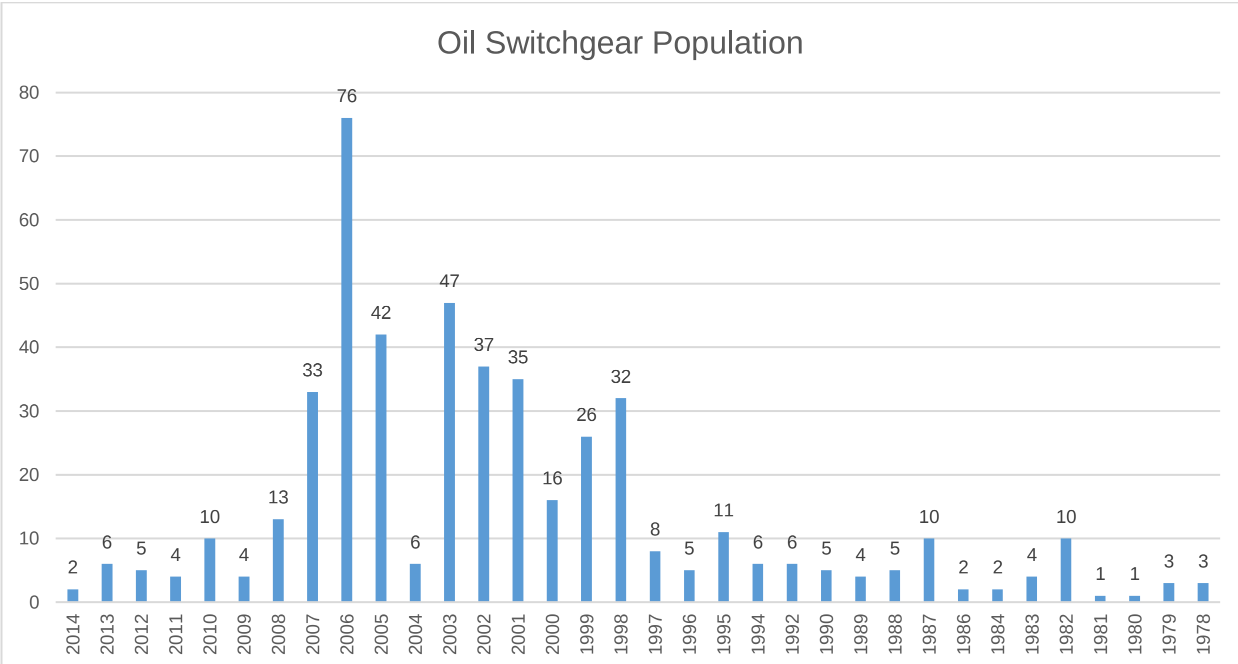


Figure A10 - 24: Oil Filled Padmounted Switchgear Age Distribution



Replacement Switchgear

Units replaced on the 27.6 kV system will be replaced will be replaced with new solid dielectric units, or units insulated with sulfur hexafluoride (SF_6). Alectra Utilities plans to install solid dielectric switchgear where possible instead of SF_6 insulated units. Solid dielectric insulation does not pose safety and environmental risks while SF_6 gas, when leaked into the atmosphere in large quantities will contribute to global warming and if leaked in enclosed space will displace oxygen, creating a safety risk. SF_6 units will still be required due to fault rating limitations of solid dielectric switchgear. This is due to the fact that the solid dielectric insulating material available on the market today is of a lower fault rating then SF_6. Based on the system fault level Alectra Utilities will install devices rated accordingly. This is also explained in section 5.3.3.

In certain cases, SCADA connectivity will be added to newer switchgear as part of these investments. These investments will enable them to be remotely controlled from the control room, or alternatively can be integrated into a Distribution Automation (DA) scheme. Figure A10 - 25 provides an image of one the many versions of an automation cabinet for pad mounted switchgear. These automation-ready switchgears will introduce a number of benefits, including the ability to rapidly perform isolation, sectionalizing and restoration during emergency situations.

These types of operations can be completed in as little as 1 to 15 minutes under a DA scheme when compared to the process of manual switching, which can take 1 to 4 hours to perform. In addition, these automated units provide telemetry that can help more readily identify cable faults and provide current readings, which can support both Alectra Utilities' ability to restore power, manage load and optimize asset management.

Figure A10 - 25: Automation Cabinet on Switchgear

3.4 Options Analysis

Alectra Utilities considered four strategies were to address deteriorated switchgear, as described below and are detailed in Table A10 - 8.

Table A10 - 8: Investment Options and Pacing for Switchgears

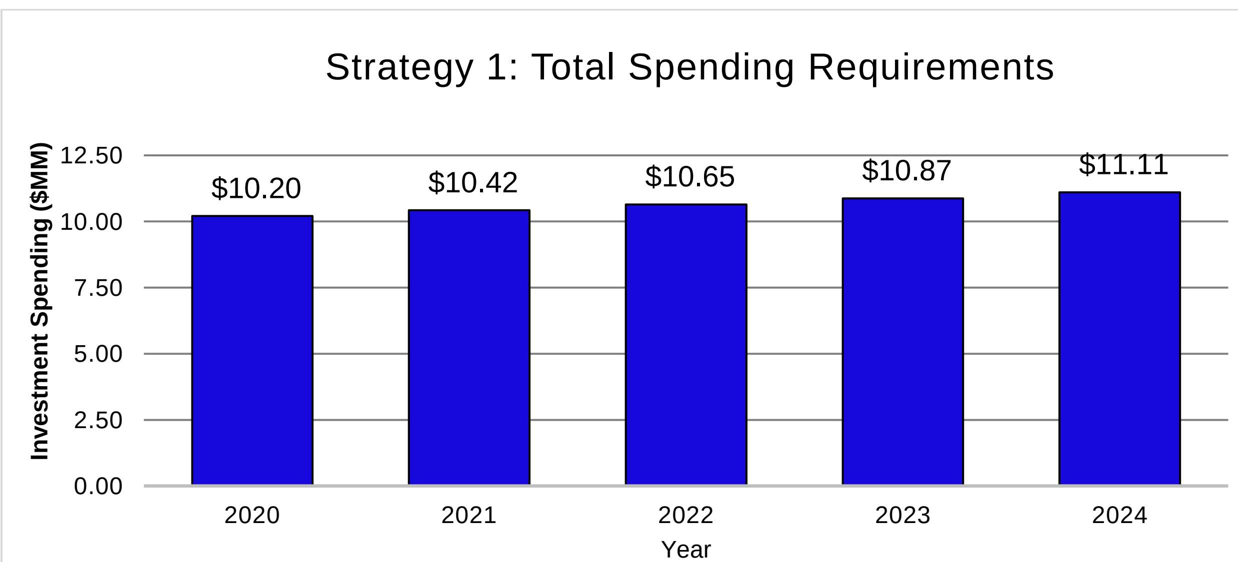
Plan	Plan Period (years)	Quantity per Year	Investment Cost
Accelerated pace	5	117	$53.3MM
Moderate pace	7	80 (3 via automation)	$39.3MM
Reduced pace	10	59	$26.9MM

3.4.1 Strategy 1: Renewal of switchgear at the accelerated pace

The baseline pace is the elimination of all Very Poor and Poor switchgear over a five-year time frame.

Figure A10 - 26 illustrates the total spending that is associated with this investment strategy. Total investments over the five-year DSP period are approximately $53.3MM, and the volume of work required by this plan would not align with Alectra Utilities' available resources and system constraints. Over the 20-year timeframe, Alectra Utilities forecasts that the average number of predicted failures would be reduced to approximately 47, resulting in a 45% decrease from an entirely reactive approach and a 17% decrease from the historical 5-year average. Based on customer feedback to maintain and not improve reliability, and maintain rates, this option was not accepted.

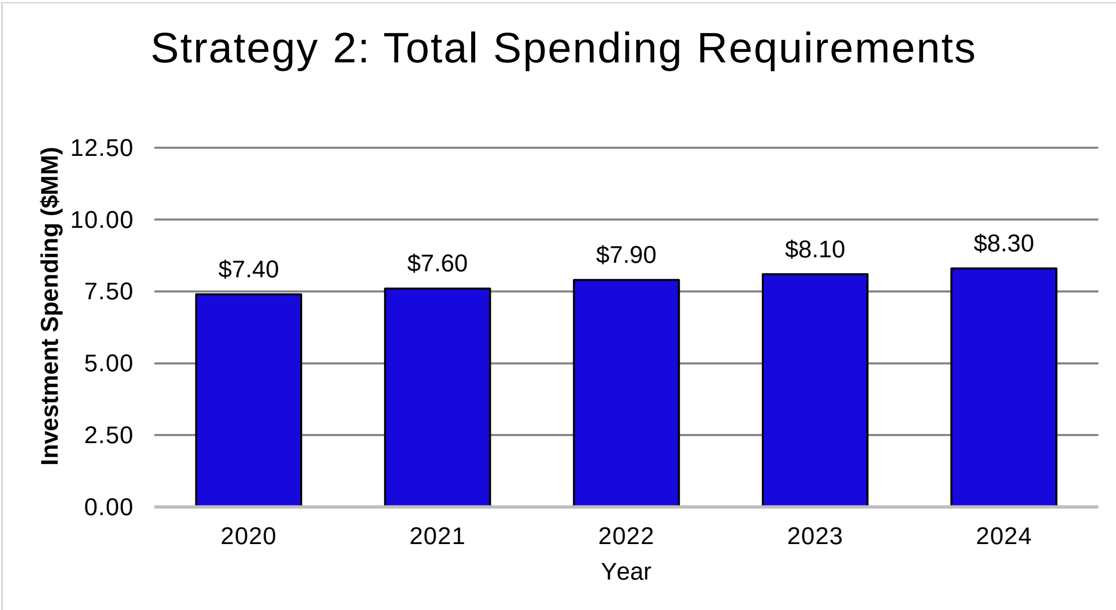
Figure A10 - 26: Strategy 1: Total Spending Requirements



3.4.2 Strategy 2: Renewal of switchgear at a moderate pace

This approach will eliminate the switchgear in very poor and poor condition over a 7-year time frame. The total investment over the DSP horizon is $39.3MM as seen in Figure A10 - 27

Figure A10 - 27: Strategy 2: Total Spending Requirements (DSP period)



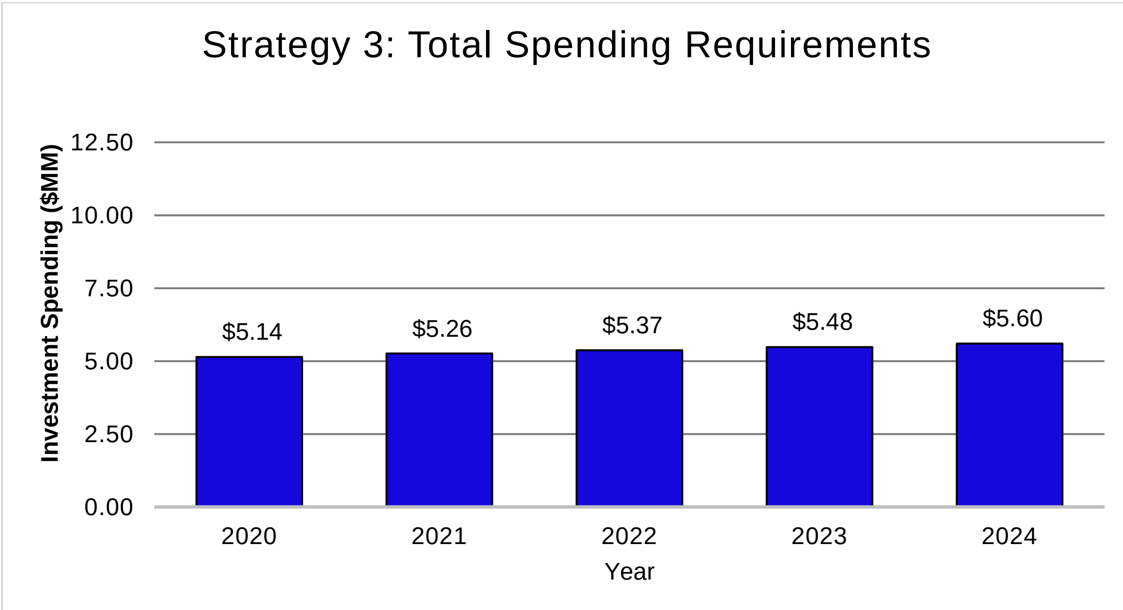
With the moderate pacing, the average number of units to replace is 80 per year (3 additional units through automation), and at the end of 2024, 91 units would be left in the backlog. Under this approach reliability due to switchgear failures would worsen until 2023 at which time the replacement rate would exceed the failure rate. Over the 20-year timeframe, Alectra Utilities forecasts that the average number of predicted failures would be maintained at 57 failures.

Alectra Utilities believes that keeping pace with projected failure rates strikes a balance between risk and cost. While the cost of this option is greater than historical spend, it is consistent with customers' preference for maintaining reliability in line with historical levels.

3.4.3 Strategy 3: Renewal of switchgear at a slow pace

The slow pace strategy would eliminate all identified switchgear in poor or very poor condition over a ten-year time frame. Figure A10 - 28 illustrates the total spending that is associated with this investment option. Total investments over the five-year DSP period totals $26.9MM.

Figure A10 - 28: Strategy 3: Total Spending Requirements (DSP Period)



Under the reduced-paced strategy, 59 units would be replaced per year on average over a ten-year period. This is far lower than the average projected failure as illustrated in Figure A10 - 18. Replacement at this pace will create a large backlog in the future, which would have a direct impact on failures and customer reliability. This outcome would be inconsistent with customers' preference that Alectra Utilities maintain reliability.

In addition, this approach would entail far greater risk of switchgear failures within the DSP period and beyond. By the end of 2024, 320 units would be in the backlog. If this 10-year pace setting trend was repeated while rates would be lower the failure rate would be higher than it is now, and has been in the last five years. Customers would have to be willing to accept worsening reliability for cheaper rates, something they have consistently indicated is not a preferred option.

For these reasons, Strategy 3 is not a practical solution as it presents an unacceptable reliability risk to Alectra Utilities' customers and would result in an imprudent backlog of necessary investment.

3.5 Summary of Switchgear Investment

Alectra Utilities plans to increase the investment in switchgear over the five-year DSP period. This is focused on reducing the number of air-insulated and oil-filled switchgear. This will have a direct reduction on the number of outages and interruption duration related to failures and will also achieve the elimination oil-filled switchgear. This increase in investment is only expected to be sustained for the next five years, at which point the expenditure will decrease and converge with historical levels. The four strategies present various scenarios of increased risk associated with reduced switchgear replacement as a trade off against lower investment levels over the DSP period.

The recommended pace is Strategy 2: maintain the moderate pace of investment, at 80 switchgears/year (3 additional units from automation) over the DSP period. This option has the least total spending over the next 20 years. While this strategy entails a short-term cost increase, this approach assumes some risk and lowers the annual spending to mitigate rate impacts to customers. It strikes a balance between risk and cost for these assets. Alectra Utilities rejected Strategy 3 due to the spending increases required from 2025 to 2038 and in the case of Strategy 1 no risk being assumed by the utility which is not beneficial to customers. For these reasons, Strategy 2 is the optimum solution.

IV Civil Structures

4.1 Investment Description

This section summarizes the proposed investments to address deteriorating civil infrastructure in Alectra Utilities' underground system. The specific drivers, need, and options considered to address these assets are set out in section 4.2, 4.3, and 4.4, respectively.

In these investments, Alectra Utilities plans to systematically and proactively replace vault lids of the worst-rated manholes to avoid potentially serious accidents. Legacy manhole and vault lids will be replaced with new lids that are capable of withstanding the heavy loading conditions present at street level. Each location will need to be treated differently as there is no single standardized solution that can be implemented across the board. In certain cases, the vault or manhole will need to be redesigned.

Failure to address these issues has a significant potential safety risk to the general public since weak lids can collapse resulting in damage to vehicles passing over the manholes or vaults.

Depending on the vintage of the structure there will be a variety of structural/condition factors. Older chambers will have been poured in place by utility workers without inclusion of rebar as it was not standard at the time. In certain cases, the chambers are so large that steel frames were used to support the lids. Some of the chambers also have scrap material that was mixed with the concrete such as broken plates, glass bottles and other garbage material. In some instances, the lids are not rated for the vehicular traffic that drives over them. These legacy installations do not meet current design requirements in comparison to modern pre-cast structures which use rebar and have lids rated for vehicular traffic.

Table A10 - 9 summarizes the outcomes and benefits of the Underground Asset Renewal investments.

Table A10 - 9: Civil Structures Summary

Outcome	Investment Benefits and Objectives
Safety	• Replacement of vault lids and manhole covers is expected to mitigate serious safety risks to customers, as some of the existing lids do not possess the necessary criteria to withstand current loads/weights at the surface/street level.

4.2 Drivers

The primary driver of the proposed investments is to address the significant risk of failure associated with the identified civil structures, since this is the issue that will be directly addressed by the proposed expenditures.

The driver is further defined and summarized in Table A10 - 10.

Table A10 - 10: Civil Structures Investments Outcomes and Benefits

Investment Driver	Reasoning and Investment Benefits
Primary Driver: **Failure Risk**	The primary driver for these investments is the elevated risk of failure, affecting public and worker safety. The increased risk of failure is primarily driven by the elevated risk of failure associated with specific deteriorating underground infrastructure.

4.3 Need

Alectra Utilities has a number of civil infrastructures that require replacement based on inspection and assessment. Figure A10 - 29 through Figure A10 - 32 highlight some of the issues Alectra Utilities has found. Early structures were not precast, and were instead poured in place. These early structures have no rebar for support, or in some cases have rail ties used as the supporting steel. Figure A10 - 29 and Figure A10 - 30 show these larger steel beams and with the loss of concrete the rusting that is taking place. Once the beams rust out structural support is lost. Figure A10 - 31 highlights one of the other inherent risks with lid degradation. Equipment placed in the below grade chamber, as is common in certain operational areas, is now susceptible to damage from debris, such as falling concrete, which can damage equipment causing it to be replaced, or even resulting in an outage due to failure. Without investment to replace these assets they pose a risk not only to reliability but to the safety of the public since these are walked over or driven on.

Figure A10 - 29: Lid Degradation: steel supporting rusting

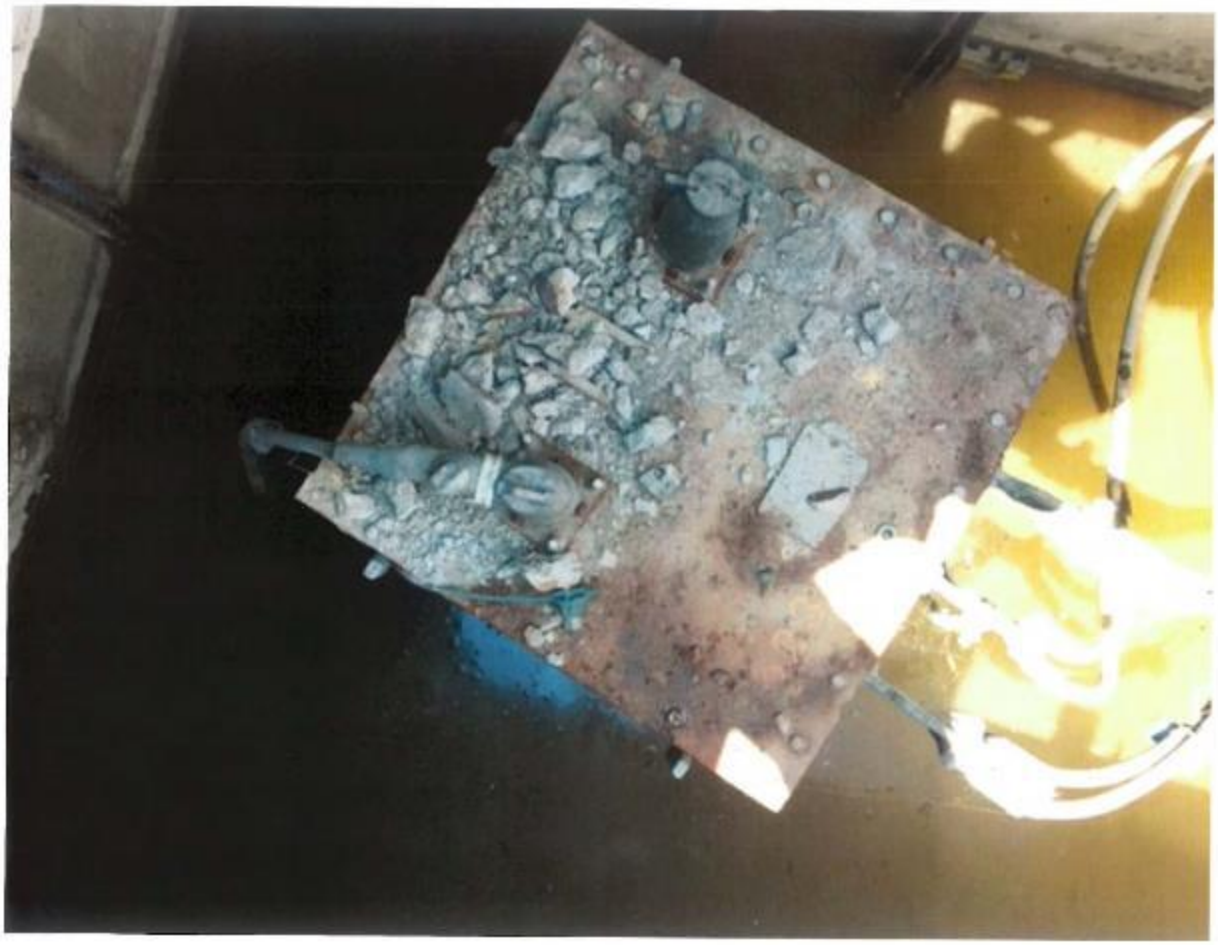
Figure A10 - 30: Lid Degradation: steel support rusting

1 **Figure A10 - 31: Lid Degradation: Cement crumbling**

2

3

Figure A10 - 32: Debris falling on equipment



4.4 Options Analysis

Table A10 - 11: Civil Structures Expenditures

	Historical Spending				Bridge	Forecast Spending				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$0.0	$0.0	$0.0	$0.0	$0.6	$0.8	$0.8	$0.8	$0.8	$0.9
Primary Driver:	Failure Risk									
Secondary Drivers:	Reliability, Functional Obsolescence, Safety									
Outcomes:	Better reliability, Easier Fault Finding, Easier Restoration, and Better Safety									

Alectra Utilities plans to invest approximately $4.1MM in Civil Structures over the DSP period, constituting less than 1% of the forecast expenditures on Underground Asset Renewal. There is no historic expenditure for this investment because failures of these assets were previously addressed reactively. While civil structures last much longer than both cable and switchgear they still degrade and are prone to failures.

For civil infrastructure, Alectra Utilities considered three intervention strategies:

- Status Quo / Run to Failure
- Replacement of the entire civil structure
- Replacement of the vault / manhole lids

Maintaining the status quo would allow for the substantive safety risks associated with these lids to continue to exist within the system. These manholes and vaults would continue to pose significant risks to the general public, as well as to the equipment located in these chambers.

Replacing the entire civil structure would result in a highly complex, lengthy and costly project for Alectra Utilities, as some vaults and manholes will be located within the roadway and not within the off-road boulevard allowance. Relocating all the infrastructure (cables, junctions) is very difficult in comparison to localized rehabilitation.

Replacing the lids only which are in poor condition along heavily travelled routes is the most cost effective in comparison to complete replacement.

4.5 Summary of Civil Structures Investment

Alectra Utilities believes that replacement of the lids which are in the worst condition is the most prudent course of action.

V Investment Timing and Pacing

5.1 Summary of Expenditures

Table A10 - 12 provides the year-over-year breakdown of underground asset renewal investments, including the historical period from 2015-2018, the 2019 bridge year, and the DSP period from 2020-2024.

Table A10 - 12: Historical and Proposed Investment Spending

	Historical Spending				Bridge	Forecast Spending				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$44.3	$43.3	$51.8	$43.6	$45.5	$61.1	$74.5	$82.2	$88.5	$95.5

The basis for historic expenditures and proposed forecast expenditures is set out for each asset group in the sections above.

5.2 Execution Approach

Alectra Utilities will leverage internal and external contractors to complete the design and installation of the new underground infrastructure to be installed within the system. The utility has retained external contractors as well as engineer contractors or consultants working at different work sites throughout the year under a multi-year Master Service Agreements. Regular progress meetings are held to ensure technical and operational issues are resolved promptly.

The execution phase will follow Alectra Utilities' internal project management methodology which provides specific guidelines, procedures, work instructions, and industry best practices that allow the project work to be performed in an economically efficient, cost effective, and safe manner.

While the planned investments target the three groups of assets described in this document, Alectra Utilities will replace other assets that are in poor or very poor condition as part of Underground Asset Renewal projects. For example, if the main goal of a project is to replace direct-buried XLPE cable that is in poor condition, and that cable connects to a transformer that is also in poor condition, Alectra Utilities may replace that transformer as part of the project, if doing so is more cost-efficient than replacing the transformer through another subsequent project.

Details of the assets to be replaced are provided in the specific project descriptions filed in Appendix B - Material Investment Business Cases.

VI Investment Projects

The material investments from 2020 to 2024 that form the Underground Asset Renewal investments are included in Table A10 - 13.

Table A10 - 13: Material Projects and Initiatives

Project Code	Project Name	CAPEX ($MM)
151091	Switchgear Renewal	$39.3
151339	Cable Replacement Project - (BA19) - Letitia - Anne - Edgehill - Ferndale, Barrie	$11.8
151325	Cable Replacement Project - (M31) - 14th - Old Kennedy - Steeles - Warden, Markham	$11.7
151409	Cable Replacement Project- Central Parkway & Bloor (29), Mississauga	$10.9
150263	Cable Replacement Project - East Left Behind Cable	$10.5
151420	Cable Replacement Project-Eglinton & Credit Valley (5), Mississauga	$10.2
151424	Cable Replacement Project-Miss. Valley & Bloor (15) Mississauga	$9.9
151336	Cable Replacement Project - (BA22) - Sunnidale and Anne, Barrie	$9.8
151404	Cable Replacement Project- Central Pk E & Miss. Valley (28)	$8.4
151407	Cable Replacement Project- Glen Erin & Burnhamthorpe (12), Mississauga	$7.3
151426	Cable Replacement Project-Southdown & Lakeshore (35), Mississauga	$6.8
151303	Cable Replacement Project - (HAM) - Stone Church - Garth - Lincoln M. Alexander	$6.6
151436	Cable Injection-011 - Area 58 & 59- Winston Churchill & The Collegeway, Mississauga	$5.5
151402	Cable Replacement Project- Montevideo & Treviso (19a), Mississauga	$5.2
150134	Cable Injection Project - (V37) - Langstaff and Weston, Vaughan	$4.8
151340	Cable Replacement Project - (V29) - Hwy 7 - Jane - Steeles - Weston, Vaughan	$4.3
151362	Cable Injection Project - (M39) - 16th - Warden - Hwy 7 - Woodbine, Markham	$4.2
151363	Cable Injection Project - (M25) - 14th - McCowan - Steeles - Old Kennedy, Markham	$4.1
151299	Cable Replacement Project - (HAM) - Millen - Barton - Fruitland	$4.0
151146	Cable Replacement and Transformers Replacement - Project - Folkway, Mississauga	$4.0
151066	Cable Replacement Project - Hamilton Mountain URD	$3.8
151435	Cable Injection- 010 - Area 56- Derry Rd W & Ninth Line, Mississauga	$3.8
151286	Cable Replacement Project - (H2) - Wanless - Heart Lake - Bovaird - Kennedy, Brampton	$3.7

Project Code	Project Name	CAPEX ($MM)
151411	Cable Replacement Project- Queensway & Mavis (31), Mississauga	$3.6
151301	Cable Replacement Project - (HAM) - Rymal - Mud - Upper Centennial - Upper Red Hill Valley	$3.3
151431	Cable Injection- 006- AREA 39- Erin Mills Pkway & Thomas St, Mississauga	$3.2
151338	Cable Replacement Project- (BA15) - Burton - Huronia - Little - Bayview, Barrie	$3.2
150257	Cable Replacement Project - (V15) - Jardin Dr, Vaughan	$2.9
150141	Cable Replacement Project – (M49) - Steeles and Fairway Heights, Markham	$2.9
150254	Cable Replacement Project - (A02) - Steeplechase Ave, Aurora	$2.9
151418	Cable Replacement Project- Innovator & Courtney Park E (4), Mississauga	$2.9
151460	Cable Injection Project - (V17) - Langstaff - Keele - Rutherford - Dufferin, Vaughan	$2.8
151367	Cable Injection Project - (M21) - Hwy 7 - Markham - 16th - McCowan, Markham	$2.8
151421	Cable Replacement Project-Rathkeale Rd & Edenrose St (6), Mississauga	$2.8
151465	Cable Replacement - Mississauga Left Behind Cable	$2.7
151141	Cable Replacement and Transformers replacement - Project - Windjammer, Mississauga	$2.7
151366	Cable Injection Project - (M19) - Markham - Steeles - McCowan - 14th, Markham	$2.7
151335	Cable Replacement Project - (BA14) - Tifffin and Hwy 400, Barrie	$2.7
151434	Cable Injection- 009- AREA 54- Highway 401 & Argentia, Mississauga	$2.5
151408	Cable Replacement Project- Burnhamthorpe & Miss. Road (13), Mississauga	$2.4
151467	Cable Replacement Project - (V17) - Langstaff - Keele - Rutherford - Dufferin, Vaughan	$2.4
151416	Cable Replacement Project- Woodchester & Thorn Lodge (34), Mississauga	$2.4
150571	Cable Injection Project - (J3-K3-N2-O2), Brampton	$2.3
151329	Cable Replacement Project - (V51) - Langstaff - Kipling - Hwy 7 - Hwy 27, Vaughan	$2.2
150262	Cable Replacement Project - (M33) - 16th Avenue and Village Parkway, Markham	$2.1
151332	Cable Replacement Project - (BA20) - Bayfield and Simcoe, Barrie	$2.0
151330	Cable Replacement Project - (A01) - Henderson - Yonge - Bloomington - Bathurst, Aurora	$1.8
151333	Cable Replacement Project - (BA9) - Little - Fairview - Harvie - Ferndale, Barrie	$1.8
151419	Cable Replacement Project- Thomas St & Hillside (24), Mississauga	$1.8

Project Code	Project Name	CAPEX ($MM)
151427	Cable Injection- 001- AREA 11- Truscott & Southdown, Mississauga	$1.7
150138	Cable Replacement Project – (BA23-BA24) - Cook St and Steel St, Barrie	$1.7
151403	Cable Replacement Project- Montevideo & Battleford (19b), Mississauga	$1.7
151413	Cable Replacement Project- Rathburn Rd W & Elora Dr (9), Mississauga	$1.6
151176	Cable Replacement Project - MS Argentia distribution feeder(s) upgrade	$1.6
151315	Cable Injection Project - (G5) - Steeles - Kennedy - Hwy 407 - Main, Brampton	$1.6
151422	Cable Replacement Project-Queen St W & Paisley (30), Mississauga	$1.5
151291	Cable Replacement Project - (I4) - Queen - Dixie - Steeles - Hwy 410, Brampton	$1.5
151331	Cable Replacement Project - (V41) - Stephanie Blvd, Vaughan	$1.5
151328	Cable Replacement Project- (21a) Darcel & Brandon Gate, Mississauga	$1.4
150261	Cable Injection Project - (V38) - Rutherford and Weston, Vaughan	$1.4
151432	Cable Injection- 007- AREA 43 & 51- Hurontario & Derry Rd W, Mississauga	$1.4
151423	Cable Replacement Project-Old Carriage Road (33), Mississauga	$1.4
151425	Cable Replacement Project-Rathburn Rd E & Tomken (10), Mississauga	$1.4
151292	Cable Replacement Project- (K4) - Queen - Torbram - Steeles - Bramalea	$1.3
151429	Cable Injection- 003- AREA36 -Matheson & Kennedy, Mississauga	$1.3
151405	Cable Replacement Project- Erin Mills & N.Sheridan (16), Mississauga	$1.2
151361	Cable Injection Project - (V26) - Teston - Keele - Major Mackenzie - Jane, Vaughan	$1.2
151144	Cable Replacement Project and Transformers Replacement - Rathburn Rd. W, Mississauga	$1.2
150025	Cable Injection Project - (V18) - Major Mackenzie and Keele, Vaughan	$1.1
150572	Cable Replacement Project - (J4) - Queen - Clark - Bramalea - Kensington - Knightsbridge, Brampton	$1.1
151143	Cable Replacement and Transformers Replacement -Project - Shelter Bay Rd. Mississauga	$1.1
150255	Cable Replacement Project - (B23) - Cundles Rd and Janine St, Barrie	$1.1
151401	Cable Replacement Project- (21b) Sigsbee & Morning Star, Mississauga	$1.0
151410	Cable Replacement Project-Roselle & Priority Cres (2), Mississauga	$1.0
150026	Cable Injection Project - (M43) - John and Woodbine, Markham	$1.0
151337	Cable Replacement Project - (BA18) - Ferndale and Benson, Barrie	$1.0
151121	Cable Injection Project - (V43) - Hwy 7 and Pine Valley Dr, Vaughan	$1.0

Appendix A11 - SCADA and Automation

I Overview

During the DSP period, Alectra Utilities plans to continue investing in Supervisory Control and Data Acquisition ("SCADA") and Distribution Automation ("DA") systems across Alectra Utilities' distribution system. These systems are a cost-effective method of improving the reliability, safety, and efficiency of the distribution system, and will allow Alectra Utilities to defer capital investments that would otherwise be needed in the near-term.

Through these investments, Alectra Utilities plans to replace obsolete, manually-operated switches with new SCADA-enabled switches and to install new fault detection and isolation equipment. These remote-controlled switches are a central component of Alectra Utilities' DA system, which relies on the ability to quickly and remotely operate switches to isolate faults and restore power more quickly to customers, and to optimize the loading of the distribution system.

Alectra Utilities plans to invest approximately $19.2MM in capital expenditures over the 2020 to 2024 DSP period. These investments primarily consist of installing new SCADA-enabled switches, as described in Section 4.3 below. Alectra Utilities plans to target the worst performing feeders and feeders with limited or no automation, as discussed in Section 4.4 below. Table A11 - 1 provides a summary of the investments, drives and outcomes.

Table A11 - 1: Investment Subgroup Summary

	Historical Expenditure				Bridge	Forecast Expenditure				
Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CAPEX ($MM)	$4.9	$5.3	$6.0	$4.5	$2.8	$3.4	$3.6	$3.7	$3.8	$4.7
Primary Driver:	Reliability									
Secondary Drivers:	Not Applicable									
Outcomes:	Reliability, Safety, Customer Value, Efficiency									

II Investment Description

2.1 Investments in SCADA and Automation

The planned investments in SCADA and Automation are designed to add new SCADA-enabled switches, reclosers, switchgear and Trip Saver assets that will be fully compatible with a DA scheme. Alectra Utilities plans to replace existing manual switches, shown in Figure A11 - 1, with SCADA-enabled switches, shown in Figure A11 - 2, and will install new SCADA-enabled switches. These investments will work in conjunction with the System Control, and Protection and Control system to ensure that all associated communications technologies, including upgraded communications hubs, enable seamless communications between switching devices.

Figure A11 - 1: Manual Load Break Operation

Figure A11 - 2: Control Box

In addition to the installation of new DA-compatible, SCADA-enabled switches, this investment will also include the deployment of Fault Detection, Isolation and Restoration (“FDIR”) technology and remote fault indicators. FDIR provides automated restoration of load, leaving only the smallest effected section out of service for investigation. Remote fault indicators would provide real-time telemetry and be enabled such that all communication functionality between the installed switches is managed directly through a centralized Advanced Distribution Management System ("ADMS"). This would automate the process of identifying where a fault/failure has likely occurred, isolate that area, and restore the remaining customers.

As noted above, these investments are necessary to expand Alectra Utilities' DA system. DA is a cost-effective way to improve the reliability, safety, and efficiency of the distribution system, and to defer capital investments that would otherwise be needed in the near-term. Each of these benefits is described below.

2.1.1 Improving Reliability

Maintaining service reliability and responding rapidly to power outages are important priorities for Alectra Utilities' customers. When combined with an effective DA system, SCADA-enabled switches provide rapid transfer of loads in emergencies, reduce restoration time which improves reliability, provide flexibility to reconfigure the system to avoid feeder and station overloads during summer peak, and provide real time system information.

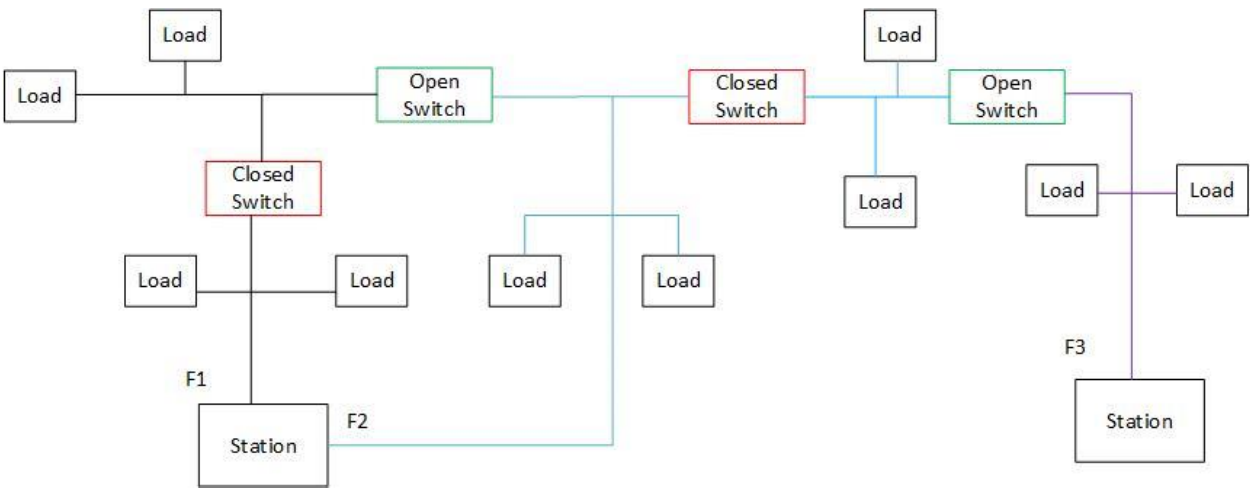
DA introduces a number of critical advantages across the system, including the ability to perform all sectionalizing, isolation and restoration activities automatically and typically under one minute. DA also enables the ability to reduce outages for unaffected customers to a momentary interruption. Since all switching is performed automatically, DA investment is highly cost-effective, as field crews no longer have to be deployed to sites to perform extensive fault locating and restoration activities. In areas where there is limited automation, deploying DA will lead to reduced SAIDI as the customers can be restored much quicker than they would have been in the case of manual switching.

2.1.2 Improving Efficiency and Deferring Large Capital Investments

DA allows Alectra Utilities to make more efficient use of the distribution system, which can avoid the need for other, larger investments in core distribution assets. DA can optimize the use of distribution assets by allowing the utility to transfer load between feeders based on the relative use of different feeders and stations. This flexible load transfer response allows Alectra Utilities to make better use of existing assets than would be possible under a traditional fixed load transfer response scheme.

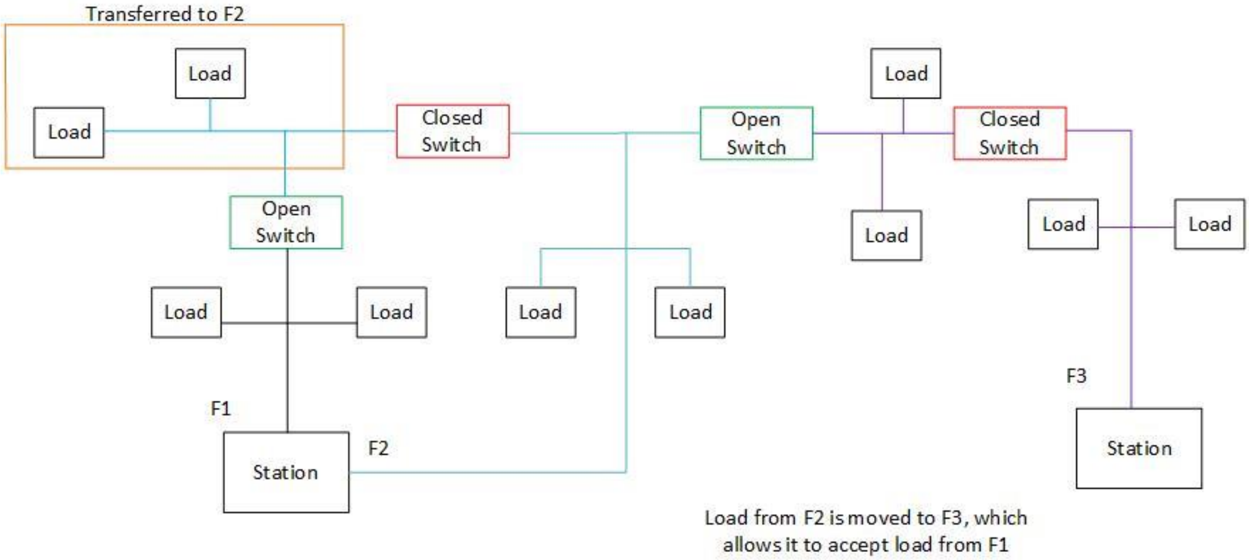
Figure A11 - 3 and Figure A11 - 4 illustrate how flexible load transfer works. In this scenario, assume that feeder F1 is heavily loaded and feeder F3 is lightly loaded. If DA was in place on all the switches[109] in the figure, the utility would be able to relieve the heavy load on F1 by transferring the two customers at the top-left corner of the diagrams to F2. Figure A11 - 4 shows the system after load has been transferred, reducing the risk of failure and power loss for customers.

Figure A11 - 3: Flexible Load (Before Transfer)



[109] Electricity travels across closed switches, but not across open switches.

Figure A11 - 4: Flexible Load (After Transfer)



Automation allows Alectra Utilities to shift load like this quickly and efficiently. Without DA, this process would normally take hours to perform manually, since crews would need to physically travel to each switch. In some situations, these switches (or ties) do not even exist. In a situation where F2 had no ties to F3 and there was no ability to shift load, this would be considered a fixed load example.

Automation can address reliability issues and defer the need for larger capital investments in some situations. There are several cases where poor feeder performance is not tied to any one significant cause. Instead, the overall condition of the feeder has made it susceptible to multiple issues such as equipment failure, foreign interference, adverse environment (pole fires), and vulnerability to adverse weather. In situations where reliability impacts have multiple causes, Alectra Utilities has found that DA is the most cost-effective way to improve reliability. Before DA, utilities would have had no option other than investing in full or partial feeder rebuilds. As technologies have advanced and costs have reduced, automation has become an effective, medium-term solution to reliability challenges, allowing utilities to identify the location of a fault and restore most customers sooner.

2.1.3 Improving Safety

The planned SCADA and Automation investments will reduce the risk of personnel injury due to travelling and operating equipment. These investments will specifically improve safety during winter conditions where equipment may be difficult to access due to snow fall and placement (snow removal piling snow near Alectra Utilities' equipment thus restricting access). Automated devices are self-contained and therefore don't require significant maintenance and reduce the risk to crews that may be caused by non-functional manual switches.

2.2 Summary of Investment Outcomes and Benefits

Table A11 - 2 summarizes the outcomes and benefits associated with the SCADA and Automation investment.

Table A11 - 2: Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Reliability	The introduction of DA allows Alectra Utilities to reduce the impact of future outages through rapid switching and restoration which is performed automatically. Outages on the "trunk" portion of the feeder will be converted to momentary interruptions, as opposed to sustained interruptions. Future problems can be avoided through the use of the data obtained from sensor technologies to be installed as part of these investments.
Safety	These investments will reduce safety risks in several respects, including: • Allowing switching to occur without requiring crews to make contact with the equipment. • Allowing switching to occur remotely and quickly during an emergency (e.g., customer contact with lines via vehicle or cut down tree, critical injury, fire or explosion).
Customer Value	Customers will experience fewer direct service disruptions within their neighborhoods, in areas where switching and restoration activities are moved to DA-enabled assets.
Efficiency	These investments will create efficiencies since field crews no longer need to be deployed to these sites to perform manual switching and restoration activities. This investment also allows Alectra Utilities to better balance and prioritize asset renewal expenditures, as DA schemes allow for future outages along the "trunk" portion of the feeder to be reduced down to less than a minute (i.e. momentary interruption). Sensor technologies will allow for critical information to be communicated directly from the field to the control room without the need of in-field personnel. In some situations, larger rebuilds are avoided with an improvement in reliability driven by automation allowing for faster fault finding and restoration.

III Investment Drivers and Need

3.1 Purpose

The SCADA and Automation investments are driven by reliability.

3.1.1 Reliability

Existing manually-operable switches present operational and safety-related issues for Alectra Utilities. These switches must be operated manually, meaning that field crews must travel to the site and travel to each individual switch as part of the restoration procedure. This overall procedure, including switching and fault locating activities can take approximately four hours on average. The procedure also exposes field crew workers to potential safety risks, which can be incurred when operating the switches – in particular those switches that are already past their end-of-life criteria. In addition, these switches contain no sensors, and therefore return no data back to the control room. Such data could be used to predict when a future reliability concern will emerge.

Outages that occur on the "trunk" portion of a given feeder introduce the most critical reliability impacts to Alectra Utilities' distribution system and its customers. These outages will trip the feeders' circuit breaker, meaning that the entire feeder will face the outage. From this point, sectionalizing, isolation and restoration activities must be executed in order to get as many customers – typically those customers outside of the immediate vicinity of the failed asset – back online. In order to accomplish this, these customers must be transferred to available tie feeders, where sufficient capacity is available to support these new incoming customers.

Figure A11 - 5 illustrates how a typical outage restoration scenario might progress both with and without advanced feeder automation. The times shown will be extended even further during storm conditions when dispatchers are juggling multiple outage events.

Figure A11 - 5: Outage Restoration With and Without Distribution Automation

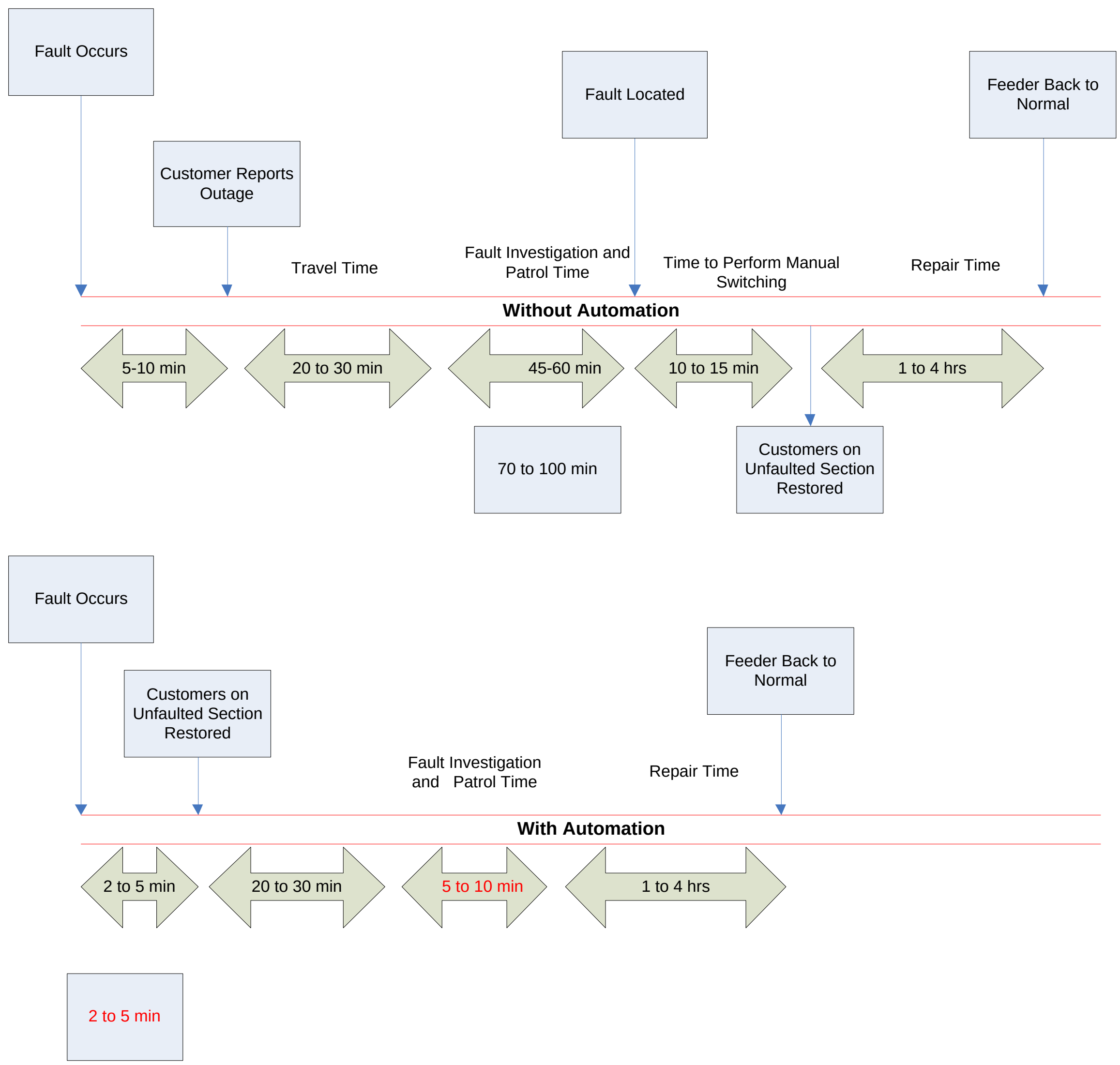


Figure A11 - 5 shows that without DA, it takes 70-100 minutes to restore power to customers on un-faulted segments of a faulty feeder. However, with DA enabling remote control of the device, the restoration time can be reduced to less than five minutes, assuming there are adequate tie points between feeders. Under an FDIR scheme, all fault locating, switching and restoration activities can be performed on average under a minute. This would drastically improve reliability for most customers, for whom sustained outages (>1 minute) would be reduced to momentary outages (<1 minute).

An alternative is to control the switches through remote switching that is executed by the power system controller at the control room. This process, however, can take upwards of 30 minutes on average, as the controller must identify available tie feeders where capacity is available in order to perform load transfer operations.

When identifying the locations for new switches under this portfolio, Alectra Utilities identifies locations that are most likely to improve service reliability for customers. The best location for an automated switch may be in place of an existing switch. In those situations, Alectra Utilities examines the impact of replacing the existing device. In some instances the benefits of replacement are clear. For example, all legacy 44 kV switches in Barrie cannot be operated under load due to safety concerns. Since the device is functionally in-operable, the reliability benefit of replacing it is obvious. Similarly, certain types of legacy switches on the 27.6 kV system are configured in a way that makes replacing a failed device longer. Replacing such a switch provides a reliability benefit to customers since it reduces the duration of outages.

Alectra Utilities also replaces switches under the Overhead or Underground Asset Renewal portfolios (Refer to Appendix A05 - Overhead Asset Renewal and Appendix A10 - Underground Asset Renewal, respectively). When the utility replaces a switch primarily due to asset health, the cost of that replacement falls under the appropriate renewal portfolio, even though the switch may be replaced with an automated asset.

Table A11 - 3: Investment Drivers

Investment Driver	Reasoning and Investment Benefits
Primary Driver: Reliability	Installing new SCADA-enabled switches as part of a DA scheme allows for faster restoration activities to occur on the feeder in question, with the outage duration being reduced to as low as less than a minute (i.e. momentary interruption). Sensors deployed across the system will help Alectra Utilities identify issues within the system before they emerge.

IV Investment Timing and Pacing

4.1 Summary of Expenditures

Table A11 - 4 provides the year-over-year breakdown of SCADA and Automation investments, including the historical period from 2015-2018, the bridge year in 2019, and the DSP period from 2020 to 2024.

Table A11 - 4: Historical and Proposed Investment Spending

	Historical Expenditure				Bridge	Forecasted Expenditure				
Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CAPEX ($MM)	$4.9	$5.3	$6.0	$4.5	$2.8	$3.4	$3.6	$3.7	$3.8	$4.7

4.2 Historical Expenditures (2015-2019)

The scope of historical SCADA and Automation expenditures was always to replace existing manual switches with new SCADA-enabled switches compatible with the DA scheme, as well as installation of new switches to support the DA scheme. Historical investment was based on larger deployments than future expenditures planned for the DSP period. This was done to leverage benefits from the automation for all the engineering and support services to install the devices. Also a higher level of penetration means that training and use by staff would be more common and beneficial for gaining experience and knowledge. Expenditures totalled $23.5MM from 2015 to 2019.

4.3 Future Expenditures (2020-2024)

Future expenditures in this portfolio are to continue implementing and expanding the DA scheme to Alectra Utilities' distribution system, including replacement of legacy manual switches with SCADA-enabled switches compatible with the DA scheme, as well as install new switches to support the DA scheme.

During the DSP period, Alectra Utilities plans to invest approximately $19.2MM in SCADA and Automation. The planned expenditures on these investments over the DSP period are lower than the average annual historic expenditures. In planning these expenditures, Alectra Utilities has considered customer feedback indicating that these types of investments should be linked to renewal and not done in advance. To that end, Alectra Utilities reduced its planned investments relative to historical levels. However, as discussed in Section 5.2.3, Alectra Utilities does need to address significant system reliability challenges over the DSP period, and believes that some level of planned spending on DA is prudent.

Alectra Utilities expects to install approximately 175 automated devices over the DSP period, with approximately 120 on the overhead distribution system and 55 on the underground distribution system. Planned expenditures in this portfolio also include the installation of remote fault indicators and communication support for FDIR implementation.

4.4 Investment Pacing and Prioritization

In order to determine potential candidates for installation of new SCADA-enabled switches, Alectra Utilities will rank the worst performing feeders based upon reliability, using FAIDI, FAIFI and SAIFI[110] contributions to the system.

Alectra Utilities will also review the outage cause codes, feeder load balancing plans and location of existing automatic switches to identify and determine the location for additional switches and reclosers wherein it is most beneficial in terms of reducing customer minutes interrupted and operational needs.

Finally, Alectra Utilities determines the optimal location for automatic switches by comparing potential switch locations to best address customer service reliability needs, feeder loading emergency back-up and load transfer needs, and control room operations needs for outage sectionalisation and restoration.

4.5 Execution Approach

Alectra Utilities will leverage internal and external contractors to complete the design and construction of the new overhead infrastructure to be installed within the system. Alectra Utilities has retained external contractors working at different work sites throughout the year under a multi-year engineering procurement construction (“EPC”) Master Service Agreement. Regular progress meetings are held to ensure technical and operational issues are resolved promptly.

[110] Feeder Average Interruption Duration Index, Feeder Average Interruption Frequency Index, and System Average Interruption Frequency Index, respectively.

Alectra Utilities considers the general risk to project schedule and cost and coordinates with third parties to mitigate some of the issues where possible, with municipalities/ region/ suppliers/ customers.

The execution phase will follow Alectra Utilities' internal project management methodology which provides specific guidelines, procedures, work instructions, and industry best practices that allow the project work to be performed in an economically efficient, cost effective, and safe manner.

V Options Analysis

Alectra Utilities has considered different options for the deployment of SCADA and Automation within the distribution system, including the following:

- Status Quo / Run to Failure
- Proceed with the Preferred Solution

The following subsections provide further information in regards to the different options that were considered.

5.1 Status Quo / Run to Failure

The Status Quo is to take no action, and allow existing manual switches to remain in place. This approach would continue to have a negative impact on system reliability and customer service, as field crews would continue to have to perform manual switching and restoration tasks, which can take up to 4 hours on average. This work also exposes the crews to safety risks, especially in cases where the existing manual switch is non-functional and past its end-of-life criteria.

Under reactive scenarios, manual switches would need to be replaced with new manual load interrupted switches. While these switches are up to modern standards, they remain manually operable, and crews must perform all fault locating, sectionalizing, isolation and restoration functions in a manual manner. Furthermore, the switching configuration will not if unites are replaced reactively. Due to a lack of available switching points along a feeder, a large number of customers may see the full outage until the affected asset is replaced/repaired. Remote fault indicators would also not be installed as per this approach. Therefore, all field data would have to continue to be collected as per manual processes by field crew workers.

5.2 Preferred Alternative

The preferred alternative is to execute the investment on those worst performing feeders in Alectra Utilities' system based upon their reliability results. This approach will ensure that any functional obsolescence concerns associated with the legacy switches are mitigated, and that reliability and safety risks are managed appropriately.

VI Investment Projects

The material investments from 2020 to 2024 that form the SCADA and Automation investments are included in Table A11 - 5.

Table A11 - 5: Material Projects and Initiatives

Project Code	Project Name	CAPEX ($MM)
100886	Distribution Automation	$18.5

Appendix A12 - Lines Capacity

I Overview

The planned Lines Capacity investments are required to ensure that Alectra Utilities' distribution system has sufficient capacity to connect the forecast new customers to the distribution system, and to alleviate capacity constraints. In doing so, the Lines Capacity investments minimize the impact of additional load growth on existing customers' service.

The Lines Capacity investments are primarily driven by three factors: (i) the rapid expansion of urban development into historically rural greenfield regions, (ii) the intensification and redevelopment of multiple downtown areas where existing supply is insufficient to meet the increased demand, and (iii) the need to address specific locations where customers currently have inadequate backup capacity due to configuration of existing supply lines.

i. Greenfield Expansion

Alectra Utilities service area spans across seventeen municipalities. In several municipalities the existing urban cores are continuing to expand into adjacent greenfield areas. These expansions are increasingly challenging Alectra Utilities' capacity to connect new customers; the existing distribution infrastructure in greenfield areas is insufficient to serve the new developments.

ii. Downtown Intensification

Alectra Utilities is also experiencing urban intensification[111] and redevelopment[112] in specific areas within its service area. The existing distribution system serving these areas cannot support the needs of the planned developments. In order to ensure sufficient capacity to connect such new developments, Alectra Utilities must expand and upgrade the existing distribution system supply lines (or "feeders") to support new development while ensuring safe and reliable service is maintained for existing customers.

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[111] Examples of this intensification include the Square One area, Lakeview development, Vaughan Metropolitan Centre, Langstaff development, as well as the Gordon Street intensification..
[112] Examples of redevelopment areas include the Port Credit area in Mississauga as well as downtown Hamilton.

iii. Inadequate Back-up Capacity

Several of Alectra Utilities' feeders are currently over the planning limit. As a result, new feeders are required to ensure adequate back up capability to meet planned outage or contingency conditions. As a result, in the event of a failure during peak load conditions on some parts of the distribution system, Alectra Utilities would not be able to restore power to customers.

In addition, there are specific locations on Alectra Utilities' distribution system that are serviced by supply lines in a "radial" configuration. Radial configuration is a legacy design for feeders. While initially less expensive to build, the radial configuration has limited backup provisions, restricting Alectra Utilities' ability to restore power during a planned or a contingency event, resulting in longer outages to customers.

1.1 Maximizing Efficiency through Coordinated Planning

In order to maximize the efficiency of the planned work, the Lines Capacity investments are coordinated with other infrastructure projects planned by local authorities. By coordinating Alectra Utilities' expansion and renewal plans with municipal and regional authorities' projects, Alectra Utilities can leverage other construction and share infrastructure with other utilities, such as telecommunications providers. Coordination of capital projects also ensures that work can be completed before construction moratoriums are placed on locations by municipal road authorities which would prevent Alectra Utilities from disturbing recently completed roads and streetscapes.

1.2 Summary of Planned Investments

Over the 2020-2024 DSP period, Alectra Utilities plans to invest $110.2MM for Lines Capacity projects. In order to minimize the impact on rates, Alectra Utilities has planned feeder expansion and upgrades with a phased approach based on feeder loading requirements paced with developments progress and system utilization. This approach ensures that the necessary infrastructure will be in service when required by customers, but minimizes the risk that Alectra Utilities' investments will outpace the growing system needs that drive these expenditures.

Table A12 - 1 provides a summary of the investments within the Lines Capacity portfolio. Key objectives within the Lines Capacity investment portfolio include:

- Expanding or upgrading overhead lines in service areas experiencing load growth locations.
- Sufficiently alleviating capacity constraints at stations and providing adequate security of supply to customers.

Table A12 - 1: Capacity Lines Investment Portfolio Summary

	Historical Expenditure				Bridge	Forecast Expenditure				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	21.2	18.6	23.8	13.4	8.0	21.1	24.0	23.9	26.4	14.8
Primary Driver:	Capacity Constraints									
Secondary Drivers:	Reliability									
Outcomes:	Reliability, Customer Value, Efficiency									

II Investment Description

This investment consists of adding new capacity into Alectra Utilities' distribution system to accommodate growth at a system level, enhance the security of supply to customers, and to mitigate loading constraints and the risk of overloading at a localized level. In order to accomplish these objectives, Alectra Utilities plans to execute the following key actions:

- Constructing new feeders as well as upgrade existing feeders, thereby connecting areas of increasing load growth to the supplying substations.
- Integrating renewable technologies, including solar/photovoltaic ("PV") and battery storage technologies, within specific portions of the distribution system that are experiencing high growth, have low reliability or are capacity constrained. The following subsections provide further details into the components of this investment. The need for these investments in set out in section 3 below.

2.1 Greenfield Expansion

The first component of this investment will involve the construction of new lines, as well as increasing capacity of existing lines, in order to provide required connections between predominantly greenfield areas where customer load is growing, and the substations that supply customers in those areas.

Example areas of greenfield load growth within Alectra Utilities' service area include the Markham Future Urban Areas, West Vaughan, Northwest Brampton, and Stoney Creek in Hamilton. Alectra Utilities is adding capacity to accommodate the imminent growth and development through the installation of new lines between nearby substations and growing areas.

The majority of new lines will be constructed with overhead distribution configuration and will involve the installation of new poles and conductors. Alectra Utilities implements present day standards and designs when constructing overhead lines. Pole lines are designed to the latest Canadian Standards Association specifications for wind and ice loading using a non-linear analysis. Overhead conductors are rated such that they can carry 600A during contingency conditions.

Present day standards also incorporate automated switching devices, including: automated switches or reclosers; switches at transformers; visible breaks for switches; as well as fault indicating devices for transformers. Constructing the distribution system to present day standards helps ensure efficiency and provides Alectra Utilities with the capability to expeditiously restore service resulting from power outages.

In general, these new lines will enable Alectra Utilities to be able to accommodate new load growth within these developing locations, while also keeping load within the planning limits on existing feeders, reducing line losses and increasing system efficiencies. The installation of new lines will enhance contingency capabilities for the utility, thereby reducing the impacts of future outages. In addition, capacity introduced from these lines will allow for new or modified load and distributed generation connections to the distribution system where there are system constraints.

Representative examples of projects within this category of investment include the following:

2.1.1 Example Project: Vaughan TS#4 (VTS4) Feeder Integration – Part #2

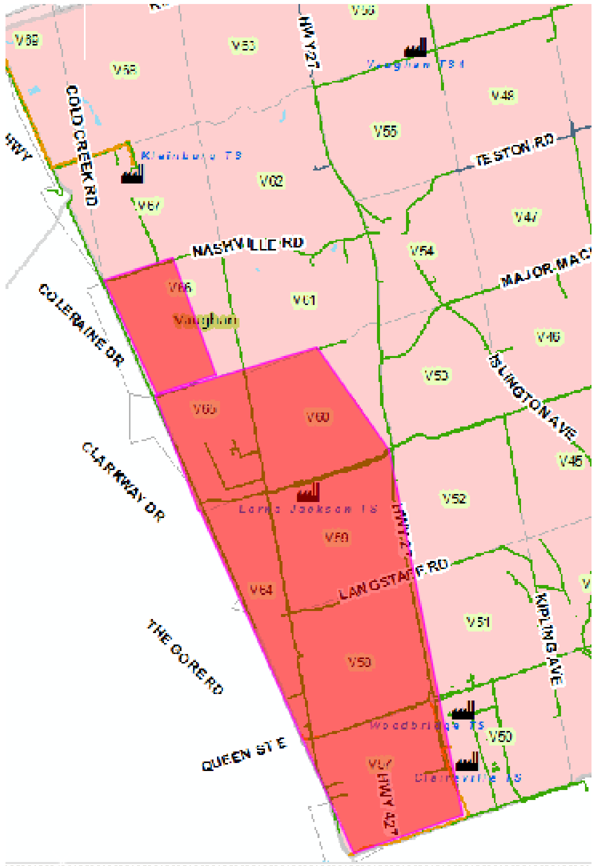
This project is the second part of a multi-part project to construct and integrate new feeders from VTS#4. The project will supply additional capacity the Vaughan West area. When complete, these investments will:

- Integrate two new 27.6 kV feeders from VTS4 into Alectra Utilities' distribution system to increase distribution capacity by 36 MW in the growing Vaughan West area; and
- Off-load existing feeders and stations.

Once fully developed, Alectra Utilities projects that the Vaughan West area will require approximately 50 to 80 MW of capacity. To serve this growing demand, Alectra plans to construct two new feeders from VTS4 which will provide 36 MW of additional capacity to the Vaughan West area.

Figure A12 - 1 shows the Vaughan West area that is experiencing significant development driven by the northern expansion of Highway 427. Without the investment to continue with the second phase of the VTS4 Feeder Integration, Alectra Utilities would not be able to fully utilize the capacity made available from the construction of VTS4 and would not have sufficient capacity available to connect the projected new developments in Vaughan West.

Figure A12 - 1: Vaughan West Area Growth Area

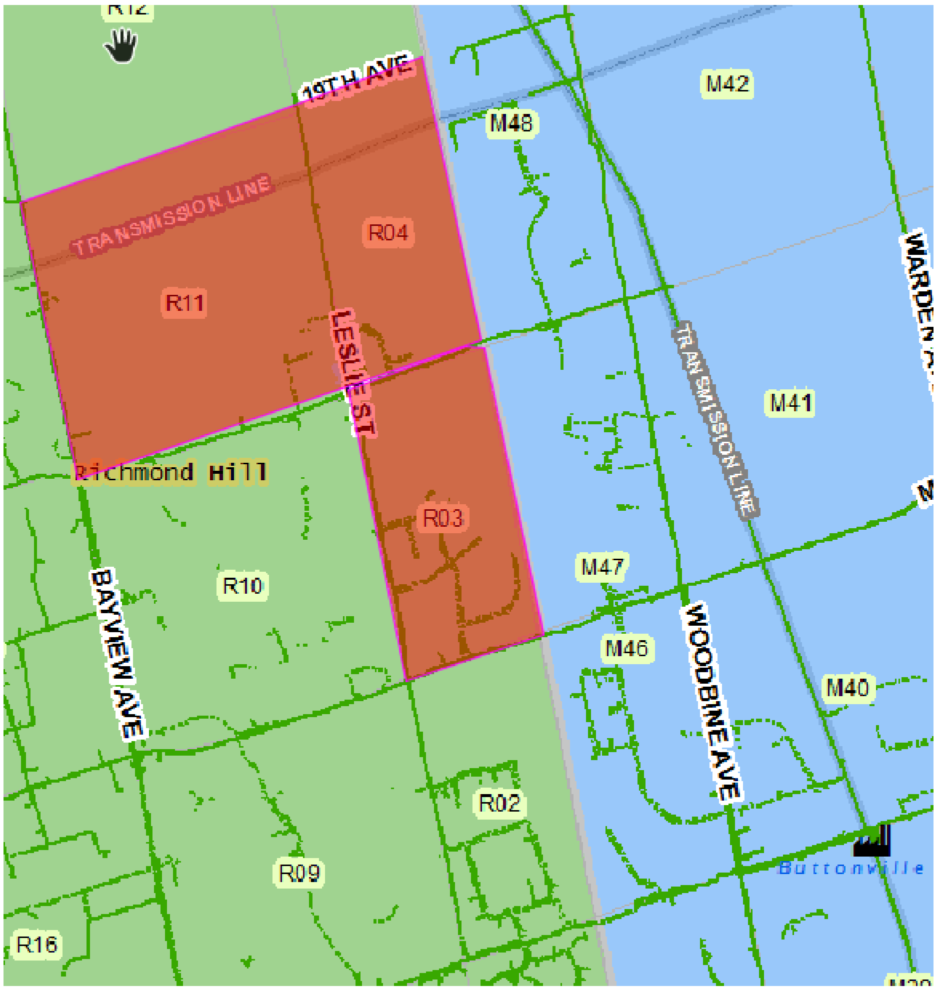


2.1.2 Example Project: Install Two 27.6 kV Feeders on 16th Ave from Highway 404 to Woodbine Ave

This project will introduce two additional 27.6 kV feeders along 16th Avenue from Highway 404 to Woodbine Avenue in Markham. This project will be completed in conjunction with York Region's road widening work to avoid future relocation.

Alectra Utilities will reroute two 27.6 kV feeders along 16th Avenue from 404 to Woodbine Avenue in Markham. The circuits will tie into the circuits from Hwy 404 to Leslie to supply new load in Richmond Hill. A large data center compound was developed in 2016 within the Leslie Street / Elgin Mills Road area in Richmond Hill. One facility, with a forecast peak demand of 16MW, was constructed in 2016. A second facility, with a forecast peak demand of 16MW, was constructed in 2018. Once fully utilized, the estimated aggregate demand for the data center compound is expected to be 60MW by 2024. Figure A12 - 2 illustrates the growth areas in the Leslie North area. Alectra Utilities has determined that the existing feeders on Leslie Street do not have sufficient capacity to supply this new load, and new feeder capacity is required. Without the investment to install two new 27.6 kV feeders in the area, Alectra Utilities will not have sufficient capacity to reliably service the existing customers nor connect additional pending developments.

Figure A12 - 2: Leslie North and Data Center Growth Area



2.2 Intensification and Redevelopment

The second component of this investment will be the construction of new lines to meet the increased loading introduced by the intensification and redevelopment of existing urban centres in Alectra Utilities' service territory. The existing infrastructure cannot accommodate the new load. Alectra Utilities will need to invest in order to connect new customers. In order to ensure sufficient capacity to connect such new developments, Alectra Utilities must expand and upgrade the existing feeders to support new development.

Areas of intensification and redevelopment in Alectra Utilities' service territory include downtown Mississauga, Lakeshore Area in Mississauga, Brampton City Centre, Vaughan Metropolitan Centre and several areas in Hamilton.

Example Project: New 44 kV Feeder Extension on Centre View Drive, Mississauga

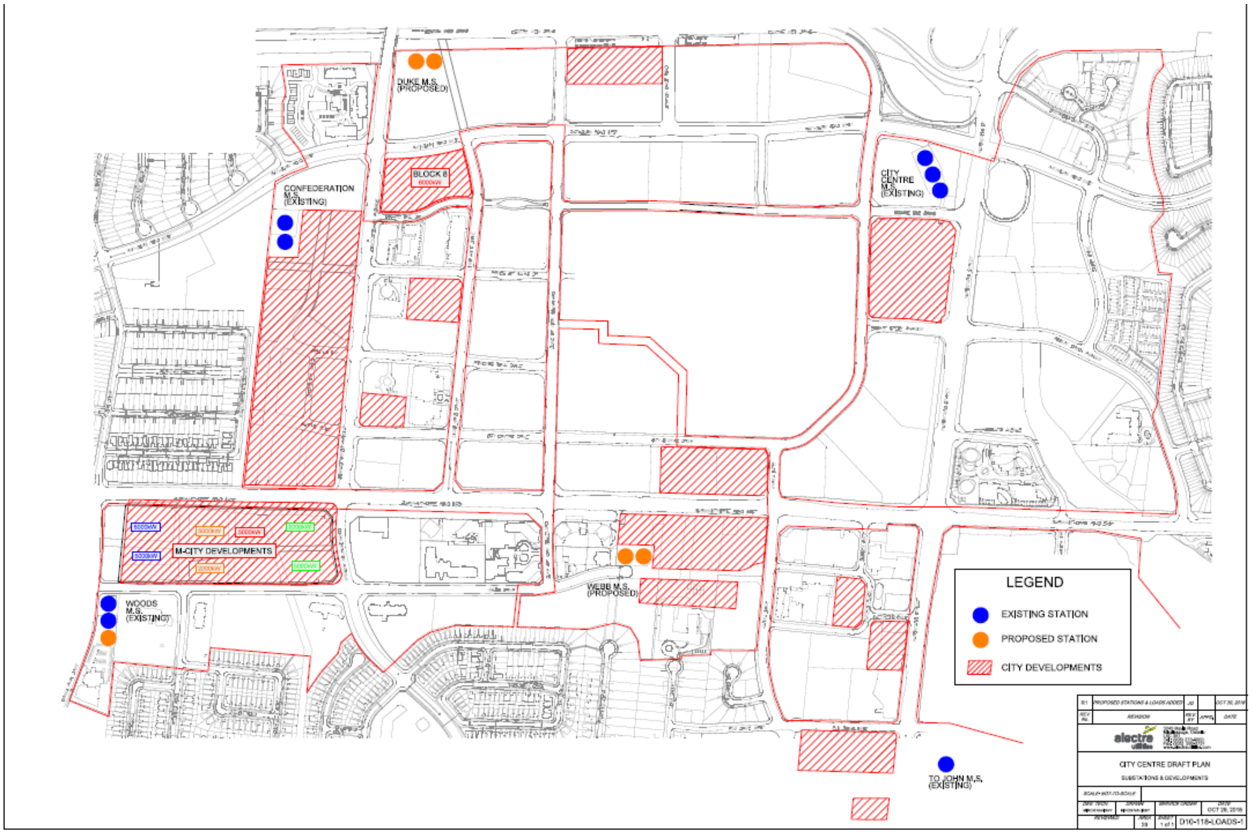
A new 44 kV overhead/underground feeder extension is needed to provide supply to downtown Mississauga area on Centre View Drive as well as provide primary supply for Duke Municipal Station (MS).

Alectra Utilities services downtown Mississauga through a 13.8 kV distribution network. Based on known development plans, this network does not have sufficient capacity to accommodate the planned developments in downtown Mississauga. Alectra Utilities has been notified of the Block 8 and Block 1 plan developments which identifies 6 buildings, each approximately 40 storeys tall, requiring 18 MVA of incremental load between Rathburn Road and Centre View Drive. In addition, there are planned office towers along Centre View drive and Rathburn which will add another 10 MW of load. In addition, Alectra Utilities is aware that several new developments require connections above the 3 MVA limit of the 13.8 kV system.[113] Without the planned investments, Alectra Utilities will not be able to connect the large developments over 3 MVA.

In order to address these customers' needs, Alectra Utilities plans to extend the 44 kV feeder on Centre View Drive from Mavis Road to Living Arts Drive to supply the new commercial developments as well as provide the primary supply for new 13.8 kV Duke MS. Once constructed, the new Duke MS will provide 20 MW additional capacity in the growing city centre. Please refer to Appendix A13 - Stations Capacity. Figure A12 - 3 illustrates the intensification growth and the proposed location of Duke MS in Downtown Mississauga.

[113] The maximum single service size that can be connected to 13.8 kV is 3 MVA as connections above causes coordination issues with the station breaker.

Figure A12 - 3: Mississauga Downtown Intensification



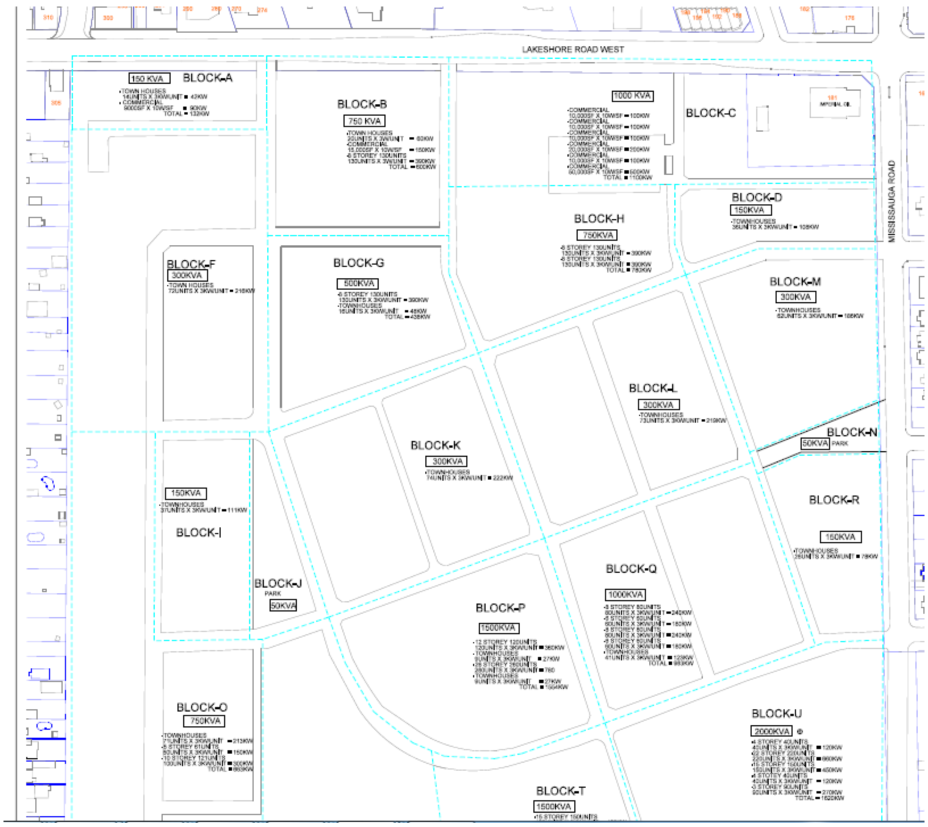
<u>Example Project: New Feeder to Support Development in Port Credit Village West, Mississauga</u>

The Port Credit West mixed development in Mississauga encompasses over 72 acres of town homes and mid/high rise commercial/residential buildings.

The City of Mississauga-approved Inspiration Port Credit project has proposed 2,500 new residential units coupled with commercial and institutional developments requiring over 12 MVA of capacity, with the possibility of further intensification beyond that. Alectra Utilities currently supplies the area via a 4.16 kV network which does not have sufficient capacity to meet the imminent supply requirements.

Alectra Utilities plans to construct a new 27.6 kV feeder on Lakeshore Road and will connect the new feeder to the existing overhead line on Mississauga Road in order to provide a looped supply configuration. Figure A12 - 4 illustrates the planned intensification in the Port Credit West area of Mississauga.

Figure A12 - 4: Port Credit West Intensification



2.3 Backup Capability

The third component of this investment is required to construct new lines to provide adequate backup capability and remediate situations where customers are supplied “radially.” Customers with radial supply have no backup source of electricity; if power is interrupted these customers cannot be switched to an alternative source of supply.

Alectra Utilities’ network design is an open grid with multiple feeders interconnected via normally open points. Feeders are designed for full backup capability over peak summer loading conditions through the switching of load to an adjacent feeder or multiple adjacent feeders to account for contingency conditions. Each feeder on average serves 400-2500 customers depending on the voltage class of the feeder. In order to facilitate restoration capability, Alectra Utilities plans the feeder load to be 2/3 the lesser of the egress cable rating or the 600 amp contingency rating.[114] For example, 27.6 kV feeder loading will be planned to a maximum of 400 amps under normal operation; 2/3 of 600 amp contingency rating. Several of Alectra Utilities' feeders are currently over the planning limit and new feeders are required to ensure adequate back up capability to meet planned outage or contingency conditions. As a result, in the event of a failure during peak load conditions on some parts of the distribution system, Alectra Utilities would not be able to restore power to customers.

Additional feeders are required to ensure adequate back up capability is available to safely and reliably operate the distribution system. Without investment to ensure system contingency, Alectra Utilities' customers that are supplied radially are exposed to significant outage durations. These customers would be stranded without service until Alectra Utilities is able to make the necessary repairs to the system during power outages.

<u>Example Project:</u> New 27.6 kV Pole Line on 19th Ave from Leslie St to Woodbine Ave, Markham and Richmond Hill

The customers on Woodbine Avenue north of Elgin Mills Road in Markham are presently supplied by a radial feeder constructed on Woodbine Avenue. As there is no pole line on 19th Avenue between Leslie Street and Woodbine Avenue, any failure on the Woodbine Avenue feeder segment between Elgin Mills Road and 19th Avenue will cause prolonged outages to approximately 400 customers in the Hwy 404 North development area of Markham.

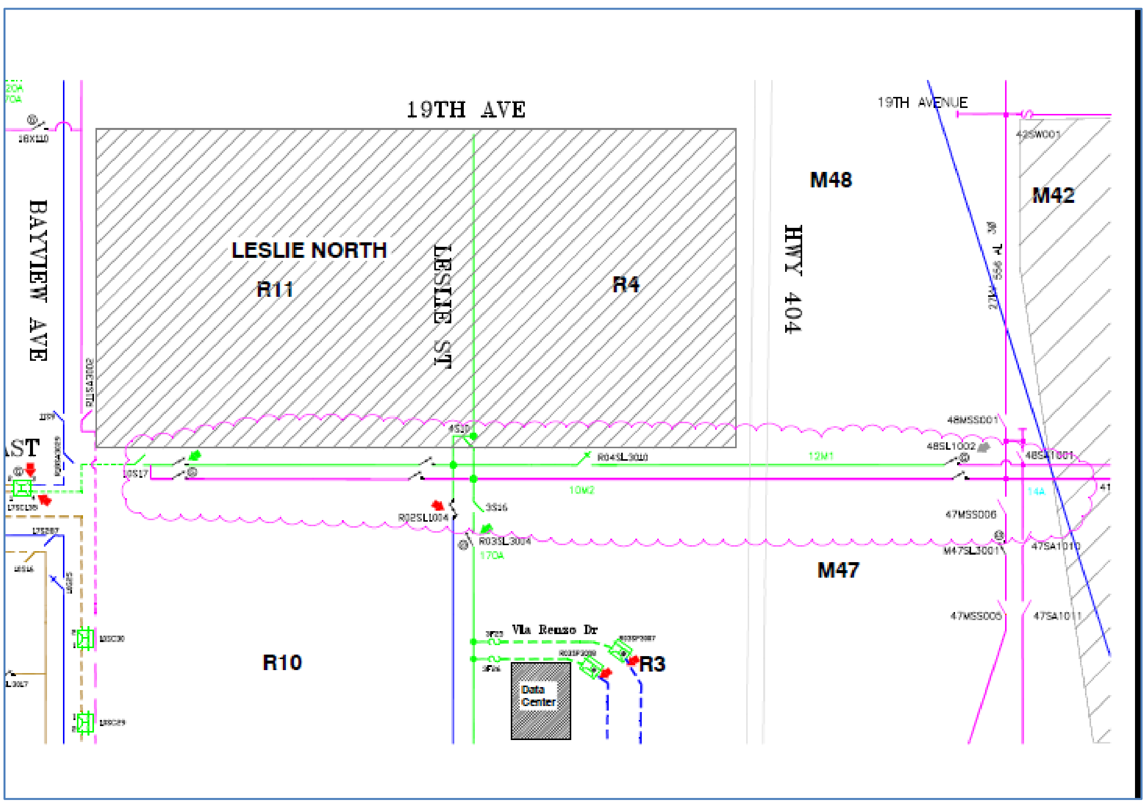
In the event of a failure, the risk of prolonged outages also applies to customers on Leslie Street north of Elgin Mills Road. Alectra Utilities currently serves these customers from a radially configured feeder on Leslie Street. As there is presently no pole line on 19th Ave between Leslie Street and Woodbine Avenue, any failure on Leslie Street between Elgin Mills Road and 19th Avenue will cause prolonged outages to customers in the Leslie North area. There are approximately 500 homes in the Leslie North subdivision that are presently impacted. Alectra Utilities is aware of ongoing development in the area and projects the imminent connection of

[114] The "egress rating" is the maximum capacity of the underground cable emanating from the station. The contingency rating is the maximum load on the feeder during an N-1 contingency situation. Typically the overhead feeders are sectionalized such that during contingency condition half the load of the feeder (approximately. 200A) can be transferred to another to another feeders.

another 500 home subdivision along Leslie Street between Elgin Mills Road and 19th Ave before 2020.

In order to address the needed capacity in the area, Alectra Utilities plans to construct a tie between feeders on Woodbine Avenue supplied by Buttonville TS in Markham with feeders on Leslie Street supplied by Richmond Hill TS to provide adequate supply contingency for the customers in the area. With this investment, Alectra Utilities will remediate the radial supply situation on both Leslie Street north of Elgin Mills Road (supplying Leslie North development in Richmond Hill), as well as the present radial supply configuration on Woodbine Avenue north of Elgin Mills Road. Figure A12 - 5 illustrates the challenges of the present day radial configuration in the Leslie North Area.

Figure A12 - 5: Radial Supply Issues on Leslie and Woodbine

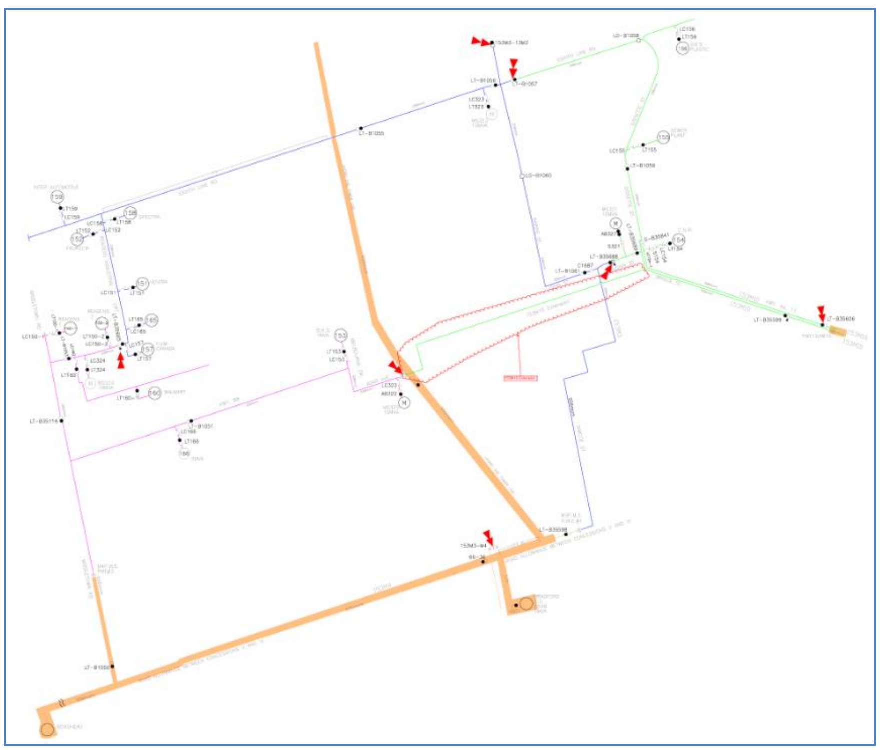


Example Project: **Extend 44 kV Feeder 153M10 to Transfer MS322 – Bradford**

The Town of Bradford is presently supplied by three 44 kV feeders. Planning information obtained from the Town of Bradford indicates that over the next ten years, an additional 1,960 residential units will be constructed along with additional industrial and commercial developments along 8th Line, Langford Boulevard, and Professor Day. Municipal plans indicate large medicinal marijuana production facilities are planned in the industrial areas of Bradford. Fig -4 illustrates the industrial and commercial growth areas of Bradford. Upon completion of the proposed developments, the 44k V feeder 153M4 will exceed planning limits in 2021.

Presently, the only tie feeder available to transfer load from feeder 153M4 is feeder 153M3. In case of a contingency on 153M4, the feeder 153M3 does not have sufficient capacity to adequately provide back up. Alectra Utilities requires investment to extend feeder 153M10 approximately 2 km westward and transfer load from feeder 153M4 to feeder 153M10. Transfer of load between the feeders enables Alectra Utilities to load balance and increase transfer capability for the customers in the Bradford area. Figure A12 - 6 illustrates the scope of the planned feeder expansion project in Bradford.

Figure A12 - 6: Bradford 153M10 Extension



2.4 Summary of Investment Outcomes and Benefits

Table A12 - 2 summarizes the outcomes and benefits associated with the Lines Capacity investment portfolio.

Table A12 - 2: Investment Outcomes and Benefits – Lines Capacity Investment Portfolio

Outcome	Investment Benefits and Objectives
Reliability	This initiative will manage system and feeder reliability through: • Ensuring system reliability by reducing the risk of failures due to highly overloaded equipment through load transfer and feeder balancing. • Improving restoration capabilities in the heavy loaded areas and fast growth areas by decreasing the number of highly loaded feeders. • Increasing operational flexibility on feeders via the installation of feeder ties to expedite restoration of outages.
Customer Value	• Ensures that Alectra Utilities has adequate capacity to connect customers on time and cost-effectively, without negatively impacting system performance for existing customers.
Efficiency	• Operating feeders within planning criteria maximizes asset life, reduces line losses and ensures required power quality levels.

III Investment Drivers and Need

3.1 Purpose

Alectra Utilities is required to ensure its distribution system can support projected load growth while maintaining reliability and quality of service for customers on both a short-term and long-term basis, as required by the Distribution System Code ("DSC"). Alectra Utilities must also connect new customers within the timelines prescribed by the OEB's service quality standards without adversely affecting the quality and safety of service to existing customers.

In order to satisfy these requirements, Alectra Utilities must maintain sufficient capacity on the distribution system to keep pace with load growth and ensure that system assets are not overloaded. Presently, Alectra Utilities is experiencing growth in a number of areas within its service territory. Notable examples of this trend include:

- **Intensification of Vaughan Metropolitan Centre**: Installation of the new Toronto Transit Commision ("TTC") subway line within this area, the Vaughan Metropolitan Centre will continue to intensify with vertical growth from new residential condominium properties and commercial developments.
- **Expansion of Markham Future Urban Areas**: Markham Future Urban areas cover approximately 1,668 acres of developable lands designated for future neighbourhoods, located primarily between Major Mackenzie Drive and Elgin Mills Road. Future Urban Area is intended to accommodate approximately 12,000 residential units with a population of approximately 38,000 persons, and approximately 19,000 jobs.
- **Intensification of Mississauga Downtown Core**: The downtown core of the City of Mississauga continues to grow at a substantial rate, with the arrival of new condo and town house development, the expansion of the Square One shopping centre and surrounding retail and commercial development, and the ongoing expansion of City and Regional transportation hubs.
- **Redevelopment and Intensification of Hamilton Downtown**: This area continues to expand with the renewal of Hamilton downtown.

Without expansion of the distribution system, Alectra Utilities will be required to operate the distribution system serving these areas beyond the rated capacities, which has multiple negative consequences. When sections of the system are operating beyond capacity, Alectra Utilities must reduce the load on the distribution system during periods of high demand or when part of the electric system fails. Without reducing load on the system, Alectra Utilities' system may fail. In addition, serving customers above rated capacity limits introduces detrimental conditions for customers (such as poor power quality) and for the utility (such as shortened asset lifecycles).

Therefore, the primary driver of this investment is to address capacity constraints, as the activities within this investment are designed to mitigate localized and feeder-level capacity-related issues. The secondary (but no less important) driver is reliability, as the new feeders and new technologies to be installed will introduce new operational flexibilities for Alectra Utilities when performing restoration during outage events.

The primary and secondary drivers are further defined and summarized in Table A12 - 3.

Table A12 - 3: Investment Drivers – Line Capacity

Investment Driver	Reasoning and Investment Benefits
Capacity Constraints	A significant amount of residential and industrial/commercial/institutional (ICI) growth is occurring within Alectra Utilities' territory, as urban areas continue to expand within adjacent greenfield areas. Presently, Alectra Utilities has very limited distribution infrastructure to support growth in such areas with insufficient capacity for future developments. New and upgraded lines will introduce capacity relief. Lines built to present standards enable Alectra Utilities to safely and reliably support new technologies in the form of DER, PV and battery storage that will further introduce localized benefits.
Reliability	By alleviating capacity constraints and overloading within the system, Alectra Utilities plans to mitigate the risk of future outages to the customer. Additional lines with inter-ties enable Alectra Utilities alternative supply paths to expedite restoration from outages and mitigate impacts of loss of supply events.

Table A12 - 4 illustrates the forecast population growth across major municipalities of Alectra Utilities' service territory over the next twenty years. Projections indicate that there will be a significant increase in both population and households within both Brampton, York Region and Guelph areas, along with intensification and redevelopment growth in the Mississauga and Hamilton areas.

Table A12 - 4: Population and Household Growth Forecast – 2016-2041

Year	Measure	Brampton	Mississauga	Hamilton	York	Guelph	Simcoe County	St. Catharines
2016	Population	593,638	721,599	536,917	1,109,909	131,794	479,650	133,113
	Households	168,010	240,910	216,325*	366,160*	52,090	173,310	57,020
2021	Population	683,700	777,730	599,400	1,245,900	148,000	499,000	136,930
	Households	189,520	252,230	228,850	408,880	59,200	194,300	58,330
2026	Population	755,710	808,260	634,300	1,349,200	158,000	537,000	142,560
	Households	210,860	265,660	245,645*	451,625*	63,200	216,030	59,720
2031	Population	811,970	842,070	669,900	1,457,400	169,000	575,000	150,590
	Households	227,610	279,140	262,450	494,380	67,600	236,760	61,120
2041	Population	890,000	920,020	740,700	1,683,600	191,000	659,000	167,480
	Households	250,460	307,470	298,400	559,160	76,400	281,500	
% Increase Population		49.92%	27.50%	37.95%	51.69%	44.92%	37.39%	25.82%
% Increase Households		49.07%	27.63%	37.94%	52.71%	46.67%	62.43%	7.19%**

Notes:	
*	This data is estimated by linear interpolation using available data
**	This percentage is based on households in 2031
1.	**All Population data for 2016 comes from:** “Census Profile, 2016 Census”, Statistics Canada. URL: https://www12.statcan.gc.ca/census-recensement/2016/dp-pd/prof/index.cfm?Lang=E
2.	**Brampton and Mississauga Population (2021-2041) and Housing (2016-2041) Data:** “Region of Peel Housing Strategy”, SHS Consulting, July 2018, URL: https://www.peelregion.ca/planning/officialplan/pdfs/2018/2018-housing-strategy.pdf
3.	**Hamilton and York Population (2021-2041) Data:** “Ontario Population Projections Update, 2017-2041”, Ontario Ministry of Finance, 2018, URL: https://www.fin.gov.on.ca/en/economy/demographics/projections/

4.	**Hamilton and York Housing (2016-2041) Data:** "Greater Golden Horseshoe Growth Forecasts to 2041", Hemson Consulting Ltd., June 2013, URL: https://www.hemson.com/wp-content/uploads/2016/03/HEMSON-Greater-Golden-Horseshoe-Growth-Forecasts-to-2041-Technical-Report-Addendum-and-Rev.-Appendix-B-Jun2013.pdf
5.	**Guelph Population (2031) Data:** https://guelph.ca/business/economic-development-office/guelph-quicksheet/ 2031 Projected Population = 169,000
6.	**Guelph Population (2041) Data:** http://placestogrow.ca/index.php?option=com_content&task=view&id=430&Itemid=14 2041 Projected Population = 191,000
7.	**Guelph Housing (2016) Data:** https://www12.statcan.gc.ca/census-recensement/2016/dp-pd/prof/details/page.cfm?Lang=E&Geo1=CSD&Code1=3523008&Geo2=CD&Code2=3523&Data=Count&SearchText=Guelph&SearchType=Begins&SearchPR=01&B1=All&TABID=1 2016 Number of Households = 52,090
8.	**Guelph Population (2021-2041) and estimated Housing (2021-2041) Data:** http://guelph.ca/wp-content/uploads/ 2012CommunityProfile.pdf Avg. No. of people per household = 2.5 is used to calculate the future projections based on this report.
9.	**St. Catharines Population (2021-2041) Data:** "How We Grow – Niagara 2041", Niagara Region, URL: https://www.niagararegion.ca/2041/pdf/mcr-pic3-boards.pdf
10.	**St. Catharines Housing (2016-2031) Data:** "Table 4-1: Niagara Region, Population, Household and Employment Forecast by Local Minicipality, 2006 – 2031", Niagara Region, URL: https://www.niagararegion.ca/living/icp/pdf/2015/Table-4-1.pdf
11.	**Simcoe County Population (2021-2041) and Housing (2016-2041) Data:** "Greater Golden Horseshoe Growth Forecasts to 2041", Hemson Consulting Ltd, Nov. 2012, URL: https://hemson.com/wp-content/uploads/2016/03/HEMSON-Greater-Golden-Horseshoe-Growth-Forecasts-to-2041-Technical-Report-Nov2012.pdf
12.	York Region- Numbers indicated are for the entire York Region. Alectra Utilities service territory includes Markham, Vaughan, Richmond Hill and Aurora.
13.	Simcoe County –Numbers indicated are for the entire Simcoe County region. Alectra Utilities service territory includes Barrie, Bradford, Thornton, Alliston, Beeton, Tottenham and Penetanguishene.

Projections outlined in Table A12 - 4 indicate that an average population growth of 41.7% and an average household growth of 44.0% respectively can be expected to occur by 2041. Although Alectra Utilities' planned investments are based on localized growth projections in specific areas, this overall trend suggests that the utility will need to continue investing to keep pace with the increasing growth in its service territory for decades.

The planned investment in Lines Capacity will accommodate the impacts of the projected load growth through the installation of new and upgraded feeders between high-growth locations and nearby substations.

IV Investment Timing and Pacing

4.1 Summary of Expenditures

Table A12 - 5 provides the year-over-year breakdown of Lines Capacity investments, including the historical period from 2015-2018, the bridge year in 2019, and the future period from 2020-2024.

Table A12 - 5: Historical and Proposed Investment Spending

	Historical Expenditure				Bridge	Forecast Expenditure				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	21.2	18.6	23.8	13.4	8.0	21.1	24.0	23.9	26.4	14.8

4.2 Historical Expenditures (2014-2019)

Historical expenditures between 2015 and 2018 is $77MM and projected expenditure in 2019 total $8MM. These expenditures focused on the construction of new and expansion of existing overhead lines to alleviate capacity constraints. The annual average of expenditures during the 2015 to 2018 period was $19.25MM per year.

Deferral of Lines Capacity investments in 2018 and 2019 was required to address urgent system renewal investments. While Alectra Utilities was able to manage with limited deferral of investment in Lines Capacity, it cannot sustain reduced expenditures any further as it has an obligation under the DSC to ensure adequate capacity is available to connect new customers as well as ensure safe and reliable power to existing customers.

4.3 Future Expenditures (2020-2024)

Capital Lines investments from 2020 to 2024 total $110.2MM. Investments in Lines Capacity provide Alectra Utilities the ability to support connection of new developments, expedite restoration of outages as well as capability to safely and reliably integrate DER, PV and battery systems. Over the DSP period, Alectra Utilities plans to invest in expanding feeders to meet the growth and the contingency capability in the 17 municipalities that Alectra Utilities serves. Relative to the last five years, the planned increase of investment in lines capacity is mainly due to the need to build feeders to support the new urban growth areas in Markham and the redevelopment of Mississauga Lakeshore, Vaughan Metropolitan Centre and areas in downtown Hamilton.

4.4 Investment Pacing and Prioritization

Alectra Utilities paces and prioritizes investments in line capacity investments by considering customer demand for additional connections, system demand growth, system reliability and coordination of other infrastructure work such as road widening, watermain expansion, as well as other utility construction.

The amount of investment required each year is paced to match timing of known development, considering available capacity, and expected load growth, net of conservation and demand side management. Alectra Utilities designs and plans projects using a phased approach based on feeder loading, funding availability and customer development progress, which allows the utility to pace investments just-in-time for connecting new developments while ensuring stable rates and maintenance of reliability for existing customers in the area.

As described in Section 5.4.1 – Capital Investment Planning Process, Alectra Utilities develops business cases for each project which identify system needs. Each Lines Capacity project proposed during the planning period of the DSP was evaluated and optimized according to Alectra Utilities' capital investment optimization process

Alectra Utilities has identified each proposed Lines Capacity project as required in the proposed timeline and determined that each investment is required to meet the pace of development in each service area to ensure sufficient capacity and reliable service for Alectra Utilities customers. Since larger projects require greater capital investment and take multiple years to build, Alectra Utilities plans to construct large projects in a phased manner to minimize the impact on rates and resources.

Customer Engagement Outcomes:

Alectra Utilities conducted a second phase of customer consultation in early 2019. The objective of the second consultation was to identify customer preferences between the outcomes of particular investment options, to inform the prioritization of specific investments in the DSP. The second round of customer preference indicated a strong support in specific system renewal investment. Although customers indicated support of Alectra Utilities investments for system service projects preference for specific system renewal project such as underground infrastructure renewal was stronger. Alectra reviewed all system service projects with the intent to adjust and prioritize investment from system service to system renewal and identified that the project to install ducts on Main Street and Queen Street can be deferred beyond the DSP period; so the investment funding was directed to reflect customer preferences.

4.5 Execution Approach

Approved projects are designed, scheduled and prepared for implementation in the next business year. The estimates are prepared based on detailed designs for 2020 projects. Estimates for the projects scheduled for 2021 through to 2024 are based on high level designs considering costs of projects similar in scope and complexity.

Alectra Utilities will utilize internal staff and external contractors to complete the renewals proposed for investments. Alectra Utilities has retained external contractors working at different work sites throughout the year under ~~a~~ multi-year Master Service Agreement**s**., to support Alectra Utilities' work requirements. This protects pricing and ensures resource availability from contractors.

Alectra Utilities implemented a formal project management platform, known as iPass, to track and manage resource allocation vs. usage, project progress vs. schedule, and financial project performance vs baseline, throughout the entire project execution phase. Regular progress meetings are held to ensure technical and operational issues are resolved promptly. Project metrics are provided and discussed with the project leads, to ensure projects track on schedule, on budget and within scope.

The execution phase follows Alectra Utilities' internal project management methodology, which provides specific guidelines, procedures, work instructions, and industry best practices that allow the project work to be performed in an economically efficient, cost effective, and safe manner.

V Options Analysis

The following options were considered when evaluating the Lines Capacity projects:

- Status Quo: Take no action to mitigate the capacity constraints within Alectra Utilities' system.
- Non-wires Alternatives
- Construct new feeders to meet system capacity requirements in pace with development first considering conservation and demand side management impacts.

The following subsections provide further details into the results from this analysis.

5.1 Status Quo

Alectra Utilities is required to ensure its distribution system can support projected load growth while maintaining reliability and quality of service for customers on both a short-term and long-term basis, as required by the DSC. Alectra Utilities must be able to connect new customers in a timely manner.

In areas of new development, if new overhead lines are not constructed, it will be physically impossible for Alectra Utilities to connect new customers to the grid.

In the case of feeders which are already loaded and nearing their capacity limits, taking no action will result in feeders becoming overloaded and exceeding their carrying capacity. Once feeders are at full utilization, load shedding will need to be executed during the summer peak period or during contingency conditions to mitigate the risk of failure from overloaded equipment. Supplying customers through highly loaded feeders may impact power quality.

For the reasons stated above, Alectra Utilities rejected the status quo or do-nothing approach.

5.2 Non- Wires Alternatives

Alectra Utilities' load forecast process considers the impact of CDM and distributed generation, which is accounted for as part of the load forecast underpinning the lines capacity projects. For urban expansion projects these options have not been considered, as new feeders are needed to connect the customers to grid. For back up projects Alectra Utilities has considered solar and storage options and determined that this option is not economical for the capacity that is required.

Based on typical loading of 15-20 MW per feeder the cost of non-wire alternatives would 15 times that of traditional solution. However, Alectra Utilities is developing projects using solar, storage and demand response to identify the circumstances in which these non-wires alternative projects can serve to provide capacity and other services in place of feeder expansions, and how they can be integrated with Alectra Utilities' control centre to perform as a dispatchable resource.

5.3 Construct New Feeders

Execution of this investment will alleviate capacity constraints and as well as ensure the availability of sufficient capacity to efficiently connect customers to Alectra Utilities's distribution system. It will allow Alectra Utilities to maintain supply to customers during contingency events and operation flexibility during maintenance and other capital work. This option will help Alectra Utilities maintain service quality and reliability standards for the existing customers as additional load is added to the system. Alectra Utilities plans to construct and configure feeders to present day technical standards to ensure customer choice for integrating distributed generation, electric vehicles and energy storage solutions.

As this is the only option that allows Alectra Utilities to reliably meet forecast connection requirements, it forms the basis of the planned Lines Capacity investments.

VI Investment Projects

The material investments from 2020 to 2024 that form the Lines Capacity investments are included in Table A12 - 6.

Table A12 - 6: Material Projects and Initiatives

Project Code	Project Name	CAPEX ($MM)
100340	Vaughan TS#4 Feeder Integration - Part 3	$8.8
150360	New build - Extend 44kV feeder Centre View Dr, Mississauga	$6.5
150692	New Feeder in Residential Subdivision Development - Alectra Central North	$3.9
150371	New build - 27.6kV Feeder Extension Traders, Mississauga	$5.5
103633	Install Two 27.6kV Ccts on 16th Ave from Hwy 404 to Woodbine Ave	$5.5
100337	Markham TS #4 Feeder Egress Part 3	$4.9
150342	HaLRT_New Stirton Feeder for TPSS#4 and 8852X load shedding, Hamilton	$4.8
150364	New build - Port Credit Village East (Marina) 27.6kV Feeders, Mississauga	$4.4
102352	Vaughan TS#4 Feeder Integration - Part 2	$4.0
100904	Install Double Cct Pole Line on Major Mackenzie - Hwy 27 to Huntington Rd	$3.7
150579	New build - Extend Bunting M81 Feeder, St.Catharines	$3.1
100924	Install two additional 27.6 kV ccts on Hwy 7 from Jane St to Weston Rd	$2.6
151233	New Construction - Campbell TS 36M63 Feeder PHASE 1 & 2, Guelph	$2.3
100909	Rebuild 27.6 kV pole line for 4 Ccts on Warden Ave from Major Mack to Elgin Mills	$2.2
150376	New build - Hamilton South Mountain feeders capacity relief, Hamilton	$2.2
150357	New build - 25M9 Extension to Derry Rd, Mississauga	$2.1
100632	27.6 kV Pole Line on 14th Ave from Hwy 48 to 9th Line	$2.0
150368	New build - North Central feeders capacity (Carlton TS to Linwell Rd/Lake St) relief, St.Catharines	$2.0
102128	Aurora MS6 Expansion	$2.0
150370	New build - 27.6kV New Feeders Lakeview Development, Mississauga	$1.9
150369	New build - 44kV Feeder Extension York/Meadowpine, Mississauga	$1.8
150390	New build - Waterdown 3rd Feeder, Hamilton	$1.7
150007	Extend 153M10 to Transfer MS322	$1.7
102547	Two Ccts on Birchmount Rd from ROW to 14th Ave	$1.6

150375	New Build - 136M10 Goreway TS Extensions, Brampton	$1.6
150217	Build double 27.6kV ccts on Teston Rd and Pine Valley Dr to supply Block 40/47	$1.4
100913	Pole Line Installation Double Cct on Major Mack - Huntington Rd to Hwy 50	$1.4
102545	Install a New 27.6kV Pole Line on 19th Ave from Leslie St to Woodbine Ave	$1.4
101036	Install a new 4 ccts CNR yard overhead crossing on the south side of Hwy 7	$1.4
101487	Add one Additional 27.6 kV Cct on Major Mack Dr and 9th Line	$1.3
101480	Build double ccts 27.6kV pole line on 19th Ave between Leslie St and Bayview Ave	$1.3
150374	New build - 13.8kV Feeder Extension 9th Line, Derry to Argentia, Mississauga	$1.2
150716	New build - 42M69 Feeder Extension Williams Pkwy - Main St to Kennedy Rd, Brampton	$1.1
150358	New build - QEW Dixie West New OH Circuits, Mississauga	$1.1
150680	Alectra Drive at Home	$2.7
102387	Install 44kV & 13.8kV Bryne Drive	$1.1
150353	Truscott Plaza - Additional capacity, Mississauga	$1.0

Appendix A13 – Stations Capacity

I Overview

Alectra Utilities' Stations Capacity investments consist of construction of new or capacity upgrades at existing substations within Alectra Utilities' service territory over the 2020-2024 period. These investments are necessary to ensure that Alectra Utilities has sufficient capacity for existing and new customers while maintaining system reliability. It also includes forward-looking development work to better utilize Non-Wires Alternatives ("NWA") for future distribution system capacity needs.

Increasing population, employment and densities within Alectra Utilities' service area are increasing the demand on the utility's municipal stations (also called substations or "MS"). Alectra Utilities' commercial, industrial, institutional and residential customer connections are increasing.[115] In areas where this customer growth is occurring, many of Alectra Utilities' substations are approaching capacity limits. Without the planned investments, Alectra Utilities may not be able to connect new customers to the distribution system, and its quality of service to current connections may deteriorate.

As discussed in Section III – Investment Drivers and Need below, Alectra Utilities plans its investments with the goal of ensuring that the distribution system has the capacity to accommodate load transfers when an element of the grid fails (referred to in electrical planning as a "contingency") and maintain supply to customers.

- The planned Stations Capacity investments focus on the Eastern and Central operational areas of Alectra Utilities' service territory: The Eastern station projects address station capacity needs in Markham, Alliston, Barrie and Bradford. The Markham station investment included in this investment relates to the cost of conducting a Class Environmental Assessment (EA) for a new Transformer Station (TS) which is required to be in service by 2027. The Stations Capacity investments in Alliston, Barrie and Bradford include the costs of land purchase, transformer upgrade or construction of new MS. These projects are discussed in Section 3.2 below.

[115] These trends are discussed in section 3.1 below.

- The Central station projects address the capacity needs in Mississauga stemming mainly from downtown growth and intensification. These investments relate to land purchases and an MS build during the DSP planning period. These projects are discussed in Section 3.3 below.
- The investment in non-wires alternatives addresses the need to facilitate the implementation of Distributed Energy Resources ("DERs") as a cost-effective solution that can be used in the modernization of the distribution system; for it to become more efficient, reliable, and provide customers with more choice. As DERs have become less costly, more sophisticated and more appealing to customers, they are increasingly able to play a role in managing the distribution system. While non-wires alternatives are not able to defer capacity in the current planning period, they are expected to become mature and provide this service in the following planning period. Developing the ability to better integrate and leverage NWA resources is described in Section 3.4.

Table A13 - 1: Investment Subgroup Spending, Drives and Outcome Summary

	Historical Expenditure				Bridge	Forecast Expenditure				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	17.0	17.6	10.3	2.4	2.7	0.8	0.8	0.8	5.2	12.0
Primary Driver:	Capacity Constraints									
Secondary Drivers:	Reliability									
Outcomes:	Ability to service existing and new customers, Reliability, Efficiency, Coordination, Environmental, Grid Modernization									

II Investment Description

Alectra Utilities' planned Stations Capacity investments consist of multiple projects for the construction of new, or the expansion of existing TS and MS over the 2020 to 2024 period. These projects will help ensure Alectra Utilities' stations can accommodate peak loading levels and that sufficient spare capacity exists such that if one station is lost in a contingency, the neighbouring stations can accommodate the lost capacity. These investments will also ensure that there is sufficient capacity to connect new customers in areas where load growth is increasing.

For each of the substations included within this investment, Alectra Utilities will be installing and upgrading one or more of the following types of assets and components:

- **Design elements**
    - High voltage breaker
    - Power Transformer
    - Low voltage main breaker
    - Feeder breakers
- **Power transformers**
    - 44 kV – 13.8 kV (20/26.6/33.3 MVA Transformers)
    - 44 kV – 13.8 kV (10/13.3/16.6 MVA Transformers)
- **Protection**
    - Digital (microprocessor-based) relays
    - Transformer Differential and Overcurrent Protection
    - Bus Differential and Overcurrent Protection
    - On-line Transformer temperature monitoring
    - On-line Transformer gas monitoring (20 MVA transformers only)
    - Feeder breaker instantaneous and time overcurrent protection
    - Feeder reclosing schemes
- **Control and Monitoring Equipment**
    - Circuit breakers

The investment also includes developing capacity in DERs with the objective of being able to leverage such assets at scale to defer investments in station capacity upgrades as well as other distribution infrastructure, which would otherwise be planned to take place in the period after 2020-2024. The DER assets will be monitored and controlled by a Distributed Energy Resource Management System ("DERMS") to allow these resources to be fully integrated into Alectra Utilities' distribution system operations, in a manner similar to that of other distribution infrastructure (e.g.; wires, switches, and transformers), thereby providing flexible solutions for the distribution system. Alectra Utilities is proposing to connect DERs to the distribution system along segments where customers would benefit from enhanced grid performance. The location of these DERs will be strategically located and prioritized to help Alectra Utilities address system challenges in high growth or poor reliability areas. See section 3.4 for a further description of these investments.

The specific projects planned during the DSP period are discussed in Sections 3.2, 3.3 and 3.4, below.

2.1 Summary of Investment Outcomes and Benefits

Table A13 - 2: Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Customer Value	Ensure adequate capacity is available to supply new and existing customer load associated with increasing intensification and population and employment growth (i.e., new residential, commercial, industrial, and institutional customers) through station transformer upgrades and new substations. Maximize the future benefit of DERs connected to the network by optimizing operations to reduce peak demand and mitigate power quality issues.
Reliability	Maintain reliability by ensuring adequate capacity and continuity of supply during contingency scenarios through station transformer upgrades, new substation build, and other Stations Capacity investments. Quantify the impact of using DERs to reducing the number and duration of outages, and improve power quality.
Efficiency	With suitable placement, scale and control capability, DERs have the potential to address certain system capacity constraints and provide support to power quality limitations. Alectra Utilities plans to examine the potential of DERS to enable the deferral of transmission related infrastructure investments.
Coordination/ interoperability	Demonstrate how non-wires alternatives can be operated through the distribution system in order to address local needs, while also participating in IESO administered wholesale markets in an efficient and interoperable manner to meet transmission needs. Without this coordination and interoperability, Alectra Utilities will not be able to optimize the application of non-wires alternatives to the distribution and transmission systems.
Environmental	Make better use of renewable and low-emission energy sources by fully utilizing renewable energy and storing surplus off-peak power to use during peak periods.

III Investment Drivers and Need

3.1 Purpose

The planned Stations Capacity investments during the DSP period are driven by capacity constraints on Alectra Utilities' distribution system, and by Alectra Utilities' need to provide reliable service. The following subsections discuss both drivers.

3.1.1 Capacity Constraints

The Stations Capacity investments are primarily driven by capacity constraints on Alectra Utilities' distribution system. As a result of green-field growth, redevelopment and urban intensification, Alectra Utilities projects that there will continue to be significant population and employment growth in the utility's service territory over the next two decades. Alectra Utilities must invest promptly to relieve loading on the distribution system and create additional capacity to reliably supply the commercial, industrial, institutional and residential customer segments, in areas which are experiencing rapid growth.

Table A13 - 3 illustrates the expected population and household growth across the four major Alectra Utilities operational zones from 2016 to 2041. These projections indicate that average population and household growth rates of will be 41.7% and 44.0%, respectively, between 2016 and 2041.

Table A13 - 3: Population and Household Growth Forecast – 2016-2041

Year	Measure	Brampton	Mississauga	Hamilton	York	Guelph	Simcoe County	St. Catharines
2016	Population	593,638	721,599	536,917	1,109,909	131,794	479,650	133,113
	Households	168,010	240,910	216,325*	366,160*	52,090	173,310	57,020
2021	Population	683,700	777,730	599,400	1,245,900	148,000	499,000	136,930
	Households	189,520	252,230	228,850	408,880	59,200	194,300	58,330
2026	Population	755,710	808,260	634,300	1,349,200	158,000	537,000	142,560
	Households	210,860	265,660	245,645*	451,625*	63,200	216,030	59,720
2031	Population	811,970	842,070	669,900	1,457,400	169,000	575,000	150,590
	Households	227,610	279,140	262,450	494,380	67,600	236,760	61,120
2041	Population	890,000	920,020	740,700	1,683,600	191,000	659,000	167,480
	Households	250,460	307,470	298,400	559,160	76,400	281,500	
% Increase Population		49.92%	27.50%	37.95%	51.69%	44.92%	37.39%	25.82%
% Increase Households		49.07%	27.63%	37.94%	52.71%	46.67%	62.43%	7.19%**

Notes:	
*	This data is estimated by linear interpolation using available data
**	This percentage is based on households in 2031
1.	**All Population data for 2016 comes from:** “Census Profile, 2016 Census”, Statistics Canada. URL: https://www12.statcan.gc.ca/census-recensement/2016/dp-pd/prof/index.cfm?Lang=E
2.	**Brampton and Mississauga Population (2021-2041) and Housing (2016-2041) Data:** “Region of Peel Housing Strategy”, SHS Consulting, July 2018, URL: https://www.peelregion.ca/planning/officialplan/pdfs/2018/2018-housing-strategy.pdf
3.	**Hamilton and York Population (2021-2041) Data:** “Ontario Population Projections Update, 2017-2041”, Ontario Ministry of Finance, 2018, URL: https://www.fin.gov.on.ca/en/economy/demographics/projections/

4.	**Hamilton and York Housing (2016-2041) Data:** “Greater Golden Horseshoe Growth Forecasts to 2041”, Hemson Consulting Ltd., June 2013, URL: https://www.hemson.com/wp-content/uploads/2016/03/HEMSON-Greater-Golden-Horseshoe-Growth-Forecasts-to-2041-Technical-Report-Addendum-and-Rev.-Appendix-B-Jun2013.pdf
5.	**Guelph Population (2031) Data:** https://guelph.ca/business/economic-development-office/guelph-quicksheet/ 2031 Projected Population = 169,000
6.	**Guelph Population (2041) Data:** http://placestogrow.ca/index.php?option=com_content&task=view&id=430&Itemid=14 2041 Projected Population = 191,000
7.	**Guelph Housing (2016) Data:** https://www12.statcan.gc.ca/census-recensement/2016/dp-pd/prof/details/page.cfm?Lang=E&Geo1=CSD&Code1=3523008&Geo2=CD&Code2=3523&Data=Count&SearchText=Guelph&SearchType=Begins&SearchPR=01&B1=All&TABID=1 2016 Number of Households = 52,090
8.	**Guelph Population (2021-2041) and estimated Housing (2021-2041) Data:** http://guelph.ca/wp-content/uploads/ 2012CommunityProfile.pdf Avg. No. of people per household = 2.5 is used to calculate the future projections based on this report.
9.	**St. Catharines Population (2021-2041) Data:** “How We Grow – Niagara 2041”, Niagara Region, URL: https://www.niagararegion.ca/2041/pdf/mcr-pic3-boards.pdf
10.	**St. Catharines Housing (2016-2031) Data:** “Table 4-1: Niagara Region, Population, Household and Employment Forecast by Local Minicipality, 2006 – 2031”, Niagara Region, URL: https://www.niagararegion.ca/living/icp/pdf/2015/Table-4-1.pdf
11.	**Simcoe County Population (2021-2041) and Housing (2016-2041) Data:** “Greater Golden Horseshoe Growth Forecasts to 2041”, Hemson Consulting Ltd, Nov. 2012, URL: https://hemson.com/wp-content/uploads/2016/03/HEMSON-Greater-Golden-Horseshoe-Growth-Forecasts-to-2041-Technical-Report-Nov2012.pdf
12.	York Region- Numbers indicated are for the entire York Region. Alectra Utilities service territory includes Markham, Vaughan, Richmond Hill and Aurora.
13.	Simcoe County –Numbers indicated are for the entire Simcoe County region. Alectra Utilities service territory includes Barrie, Bradford, Thornton, Alliston, Beeton, Tottenham and Penetanguishene.

Table A13 - 4 and Table A13 - 5 provide population and employment increases respectively, which further provide insight into the growth trends within Alectra Utilities' service area.

Table A13 - 4: Population Growth Projections (in %) by Cities/Regions[116]

City/Region	Population (% Increase from Previous Five Years)[117]							
	2006	2011	2016	2021	2026	2031	2036	2041
Peel Region	17%	12%	6%	19%	9%	8%	7%	7%
City of Hamilton	3%	3%	3%	12%	6%	6%	5%	5%
York Region	22%	16%	7%	12%	8%	8%	8%	7%
City of Guelph	8%	6%	8%	9%	9%	8%	7%	6%
Simcoe County	12%	10%	8%	4%	8%	7%	7%	7%
City of St. Catharines	1%	0%	1%	3%	4%	6%	6%	5%

Table A13 - 5: Employment Growth Projections (in %) by Cities/Regions[8]

City/Region	Employment (% Increase from Previous Five Years)[117]							
	2006	2011	2016	2021	2026	2031	2036	2041
Peel Region	14%	12%	9%	8%	5%	5%	5%	5%
City of Hamilton	7%	7%	8%	9%	5%	6%	7%	8%
York Region	20%	17%	13%	12%	7%	7%	7%	7%
City of Guelph	8%	1%	10%	8%	5%	6%	3%	4%
Simcoe County	17%	8%	9%	6%	4%	3%	7%	7%
City of St. Catharines	5%	-9%	4%	5%	3%	5%	5%	7%

Demographic projections for Alectra Utilities' service territory also reflect significant growth trends.[118] Table A13 - 3 indicates that an average population growth of 41.7% and an average household growth of 44.0% respectively is expected to occur over the 10 year period from 2016 to 2026. Table A13 - 5 indicates that an average employment growth of 38% is expected to occur over the same period. Investments in Stations Capacity will accommodate the impacts of the

[116] The numbers encompass all municipalities in each respective region (York, Simcoe County, Peel)
[117] The numbers encompass all municipalities in each respective region (York, Simcoe County, Peel)
[118] Alectra relied on data from the Ontario Ministry of Finance, Hemson Consulting (discussed below), and planning materials for the Peel and York Regions.

projected load growth through capacity upgrades at the existing stations as well as new stations builds at new growth locations.

Addressing capacity constraints in key growth areas is crucial as stations approach capacity limits. If not dealt with proactively, these growth trends will impact Alectra Utilities' ability to connect customers to the distribution system. Without the planned investments to address these trends, Alectra Utilities may not be able to connect customers in some areas.

3.1.2 Reliability

The secondary driver of these investments is reliability. Consistent with utility best practices across Canada, Alectra Utilities plans its distribution system such that the system can continue to operate within normal limits when one element of the grid fails. This is called "N-1 contingent", since the system is operating with one element less than it normally does. In the context of substation planning, this means that Alectra Utilities must be able to transfer the loads associated with any given transformer in the substation network to adjacent substations, while remaining within the substation transformers' contingency ratings.[119] In a network comprised of three or more substations, the N-1 contingency standard is satisfied even if substation transformers in the network are loaded beyond 50% of the contingency rating.[120] The planned investments are necessary for Alectra Utilities to provide customers with a level of reliability consistent with the N-1 contingent standard.

3.1.3 Preparing for a Distributed Energy Connections

The ability to integrate new technologies which can provide customers with more choice, improve reliability or reduce the impact on the environment was identified by Alectra Utilities' customers

[119] The contingency rating is determined by the cooling capabilities of the transformer and is equivalent to the highest cooling rating; i.e., Oil Natural Air Natural (ONAN) (100% of nameplate rating) for self-cooled transformer units, Oil Natural Air Forced ("ONAF") (133% nameplate rating) or ONAF/ONAF (166% of nameplate rating) for transformer units with single and dual stage fans. The ONAN rating is the normal rating of the transformer without additional cooling, while the ONAF rating is the maximum permissible loading on the transformer before exceeding the permissible loading of the transformer.

[120] A minimum of three substations is required to fully satisfy the N-1 contingency criterion when loading exceeds 50% of the transformer contingency rating. Due to the minimum of three substation requirement to satisfy the contingency criterion, Alectra applies the triad criterion, which ensures that upon loss of a single substation transformer, the two remaining transformers can accommodate the transferred load in addition to their native load, thereby mitigating any potential load shedding or stranded customers as a result of the outage.

as one of the top three priorities during the customer engagment. As customer preferences with respect to energy evolve in favour of more choice and greater control and customization, as evidenced by customers' growing levels of adoption of distributed generation and smart thermostats, traditional distribution system planning and operation needs to change as well. While rapid technological innovation is driving down the costs of energy technologies, an increasing level of DER penetration will change how the traditional distribution system is operated. These changes must be understood, and reflected in the planning and operation of the grid through higher visibility of DERs, effective communication between the utility and DERs owners, and coordinated operations.

The NWA project is driven by the following needs to:

- Evaluate non-wires solutions as system planning alternatives to be used to manage local peak demand; increase reliability and efficiency; and to defer or avoid capital and operating costs associated with distribution infrastructure;.
- Test the integration and customer adoption of new technologies which can provide customers with more choice, improve reliability and/or reduce the impact on the environment; and
- Increase the readiness of Alectra Utilities' distribution system to facilitate and support the integration of new energy technologies, including: electric vehicles; electricity generation technologies; battery storage; and home automation.

Understanding effective use cases for non-wires alternatives will enable Alectra Utilities to deploy them where they are feasible solutions, in order to defer or avoid more costly transmission and distribution infrastructure. The York region, specifically Vaughan, has been identified as an area of emerging load growth and thereby an optimal area where non-wire alternatives may provide system benefits and value.

By undertaking this investment now, Alectra Utilities is preparing the distribution system to efficiently, safely and reliably respond to the expected uptake of DERs and balance the benefits of DERs to customers while cost-effectively modernizing the distribution system. Without this preparation, Alectra Utilities introduces the risk of:

- limiting customer choice due to constraints in the distribution system to integrate and support DERs,
- Missing opportunities to reduce peak demand and defer and/or reduce traditional distribution investment using DERs that are coming into existence
- Performing reactionary infrastructure upgrades to maintain power quality and reliability standards or meet capacity needs.

The primary and secondary drivers are summarized in Table A13 - 6.

Table A13 - 6: Investment Drivers

Investment Driver	Reasoning and Investment Benefits
Primary Driver: Capacity Constraints	The projected increase in load will constrain the ability of the system to provide consistent service delivery. Alectra Utilities has identified capacity constraints that it must address in order to ensure timely supply to new developments through investment in transformer upgrades and substation construction. New Stations Capacity investments also benefit the system through the additional capacity for customer connections and increased flexibility in system supply configurations. Exploring and understanding the potential of using location targeted DERs as a non-wire alternative will provide long-term benefits to Alectra Utilities and its customers by understanding when these investments can defer or avoid costs associated with traditional infrastructure.
Secondary Driver: Reliability	In order to continue meeting minimum reliability, consistent with the N-1 contingency planning standard, Alectra Utilities must make the planned investments in its stations. Failure to make these investments could result in a situation where Alectra Utilities is unable to sufficiently transfer customer load when an element of the grid fails, resulting in significantly decreased reliability in areas of the distribution system.
Secondary: Customer access and choice	As demonstrated in the customer engagement where approximately 42% of Alectra Utilities' residential customers and 37 of 62 medium sized business customers indicated support for some investment to prepare for the adaption of new technologies. These investments support the growth of distributed renewable generation on the system, that in turn offset generation and transmission investment to the benefit of rate payers and that also create environmental benefits.

The following subsections provide further details regarding the specific projects planned for the 2020-2024 DSP period. The planned investments are divided between Alectra Utilities' Eastern and Central regions, which are set out in Sections 3.2 and 3.3, respectively. Investments in NWA are listed in Section 3.4. Alternatives to each proposed investment are set out in Section 5.3.

3.2 Eastern Stations Investments

3.2.1 Markham - New Transformer Station TS5 (Class EA)

This investment is to support the completion of the Environmental Assessment] ("EA") that is required for the construction of the new Markham TS#5, as identified by the Independent Electricity System Operator's regional resource planning process. Alectra Utilities' load forecast indicates that the transformation capacity of the distribution system in the Markham/Richmond Hill area will be exceeded by 2027.[121] The projected in-service date for the new station is 2027, as required to meet anticipated load growth. Alectra Utilities forecasts expenditures of $0.71M on Markham TS5 during the DSP period.

The Markham and Richmond Hill area is serviced by a 27.6 kV distribution network supplied via 8 TS that connect to the 230 kV transmission system. As of 2018, the area has a population of approximately 569,000, and 14,200 businesses with 270,020 employees.

The Region of York revised its Official Plan in 2016 to align with the 2041 Provincial targets, as set out in the *Places to Grow Growth Plan*[122] for the Greater Golden Horseshoe:

- The Growth Plan projects the addition of 613,900 residents and 305,100 jobs from 2016 to 2041. This growth is anticipated to be spread throughout the Region of York.
- Between 2019 and 2028, Markham and Richmond Hill are projected to add approximately 37,145 residential units (27,720 unit in Markham and 9,425 units in Richmond Hill) and

[121] Alectra Utilities' forecasts reflect current capacity and given the expected impact of distributed generation and CDM.
[122] "Growth Plan for the Greater Golden Horseshoe (2017)" Queen's Printer for Ontario, May 2017. URL: http://placestogrow.ca/images/pdfs/ggh2017/en/growth%20plan%20%282017%29.pdf>

2.9 million square meters of commercial/industrial space (2.1 million square meter in Markham and 0.8 million square meter in Richmond Hill)[123, 124]

- Between 2019 and 2028, the total peak demand in the Markham/Richmond Hill area is expected to grow by approximately 310 MW. Alectra Utilities expects that Conservation and Demand Management ("CDM") and distributed generation will lower the peak demand by 22MW over the period from 2019-2028 and the net demand will be 290MW.

In 2015, the IESO's York Region Integrated Regional Resource Plan identified the need for a new station in Markham by 2022. In April 2017, the IESO issued a hand-off letter to Alectra Utilities and Hydro One concerning the implementation of a wires solution. The recommended scope of the project consists of a new 230/27.6 kV 170MVA Dual Element Spot Network ("DESN") TS in Markham connected by distribution and transmission lines.

Alectra Utilities expects that the total demand will exceed existing system capacity in 2027, and that a new transformer station will be required to meet the capacity needs. The timeline to build the new station is approximately 3-5 years, including the EA process. Alectra Utilities intends to complete the EA for the new TS in 2023/2024 so that station design can begin in 2025, for an in-service date of 2027. The exact location of Markham TS5 will depend on the outcome of the EA, including the associated public consultation process.

3.2.2 Alliston – New 10 MVA Station

During the DSP period, Alectra Utilities expects that the demand from forecast residential and Industrial/Commercial developments in the Town of Alliston will exceed the utility's capacity. Alectra Utilities must build a new 10 MVA MS in order to meet the growing demand in this region. Without the planned MS, Alectra Utilities would be unable to satisfy the N-1 contingency standard,

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[123] "Development Charges Background Study" Hemson Consulting Ltd. February 14, 2018. URL: <https://www.markham.ca/wps/wcm/connect/markham/2181568f-16c1-4b5f-bf19-d3842c7ebf97/DC-Background-Study-Staff-Consolidation-Report.pdf?MOD=AJPERES&CONVERT_TO=url&CACHEID=ROOT WORKSPACE.Z18_2QD4H901OGV160QC8BLCRJ1001-2181568f-16c1-4b5f-bf19-d3842c7ebf97-mxh-xgH>

[124] "Town Of Richmond Hill Development Charge Background Study" Watson & Associates Economists LTD., May 9, 2014. URL: <https://www.richmondhill.ca/en/shared-content/resources/documents/town-wide-dc-background-may9.pdf>

meaning that customers in this region would be exposed to unacceptably high reliability risks. Alectra Utilities forecasts expenditures of $5.5M on the new station during the DSP period.

The Town of Alliston is currently supplied by two 13.8 kV stations: MS330 and MS331. MS330 has a 10 MVA single-stage fan transformer rated to 10 MVA Oil Natural Air Natural (ONAN) and 13.3 MVA Oil Natural Air Forced (ONAF) supplying north-west Alliston.[125] MS331 has two 10 MVA transformers each supplying separate parts of Alliston: MS331-T1 feeders supply the east-end of Alliston, and MS331-T2 feeders supply west-end of Alliston. These two transformers have single-stage fans and are rated to 10 MVA ONAN and 13.3 MVA ONAF.

There are two major industrial/commercial developments and several residential developments planned in the Alliston region during the 2020-2024 DSP period. Each development is shown on the map in Figure A13 - 1 and described below.

Westerly Industrial/Commercial Development

Growth projections obtained from the Town of New Tecumseth indicate that a 56-hectare industrial and commercial development (Westerly ICI) is planned to be completed within six years in the vicinity of Dufferin Street and Industrial Parkway.

The Westerly ICI lands have been marketed internationally as investment ready under Ontario's Certified Site Program with proximity to major highways, Honda Canada, and the Greater Toronto Area.

Easterly Industrial/Commercial Development

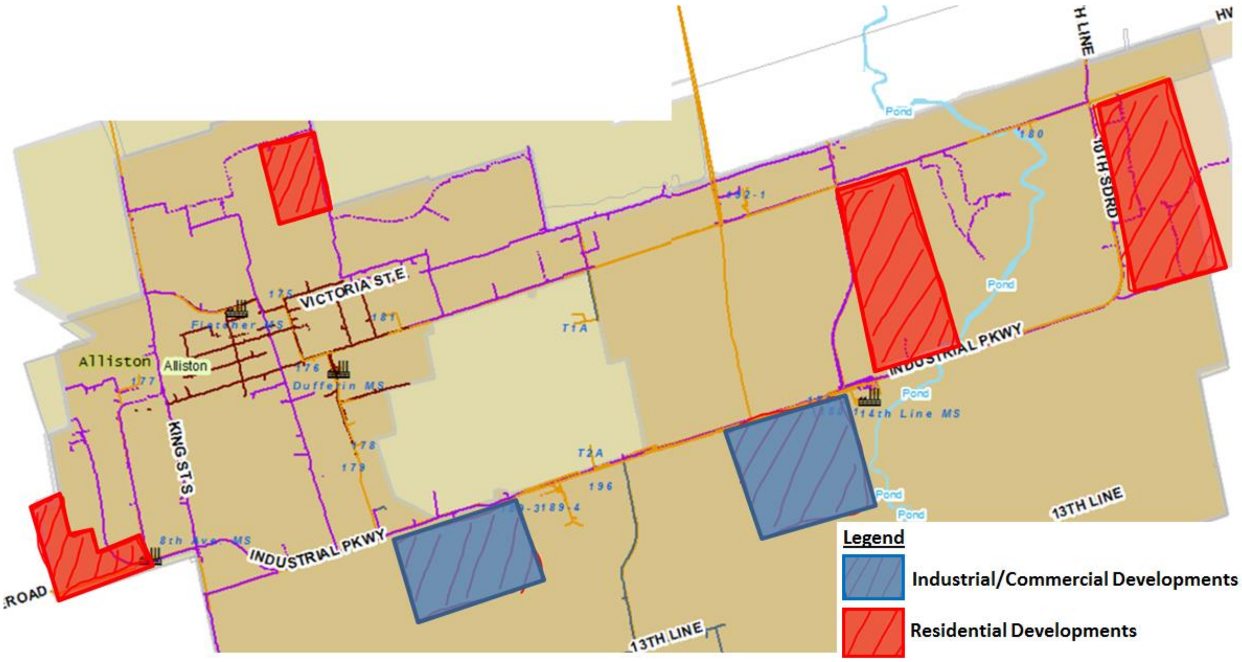
Another 30 hectares industrial and commercial development (Easterly ICI) is proposed to be developed over four years in the vicinity of Theatre Road and Industrial Parkway. The Easterly ICI development has draft plan approval from the Town of New Tecumseth for an industrial plan of subdivision (File No. NT-T-1301) with approval for a period of two years until July 13, 2020. The draft plan proposes 12 blocks for industrial purposes and 3 blocks for commercial use

Residential Developments

[125] See footnote 119 for a discussion of transformer ratings.

A total of 2,680 residential homes are to be completed in the Alliston area over from 2019-2023. In some developments, construction of Phase 1 has been completed, with the remainder of phases to be completed over the next few years. The projected growth in the Town of Alliston is illustrated in Figure A13 - 1.

Figure A13 - 1: Town of Alliston and Associated Commercial Developments



As described below, the forecast load growth in Alliston will (i) over-load one feeder, and (ii) exceed Alectra Utilities' capacity to shift customer between feeders when an element of the grid fails (i.e., N-1 contingency).

The forecast growth will over-load one of the existing feeders (MS331-T2). Upon completion of the residential developments, MS331-T2 will exceed its 10 MVA ONAN nameplate rating in 2020, and its 13.3 MVA ONAF maximum rating in 2023. In the existing feeder configuration, the 13.8 kV component of the proposed Westerly ICI and Easterly ICI would be supplied by MS331-T2, further exceeding the substation 13.3 MVA ONAF rating. In addition to these concerns, the completion of the proposed developments will result in Alliston not having adequate contingency capacity in the event of loss of either transformer at MS331, meaning that customer could not be transferred to another supply in the event of an outage. If the distribution system were to fail in such a situation, service could be interrupted to a large number of customers for an extended period.

The forecast customer growth in Alliston will also prevent Alectra Utilities from being able to shift load between feeders and restore power during outages. From an overall system perspective, the historical loading across all 13.8 kV substations in Alliston peaks at 23.4 MVA, which is within the total capacity for Alliston's 13.8 kV system, which is 39.9 MVA. However, the contingency capacity of the Alliston system with loss of the largest transformer is 26.6 MVA. If the customer load exceeds this level, Alectra Utilities may not be able to continue operating the system within nominal limits when an asset fails. When the new developments are completed, Alliston is projected to experience a total of 37.6 MVA in 13.8 kV station load. This load would exceed the system's contingency capacity of 26.6 MVA upon loss of one large 13.8 kV substation transformer. Alectra Utilities' standards require that during an N-1 scenario (such as loss of a substation transformer) adequate capacity should be available at adjacent substations for contingency backup. Without the new station, Alliston's transformer capacity would not satisfy the N-1 contingency.

Table A13 - 7: Alliston 10-Year Load Growth Projection

Station Information				Alliston 10 Year Load Growth Projection (MVA)									
Station ID	Station	ONAN Rating (MVA)	ONAF Rating (MVA)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
MS330	8th Avenue	10	13.3	8.0	8.5	8.7	8.8	8.9	9.0	9.1	9.2	9.3	9.5
MS331-T1 (13.8 kV)	14th Line	10	13.3	8.8	9.1	9.1	9.2	9.3	9.4	9.5	9.6	9.7	9.8
MS331-T2 (13.8 kV)	14th Line	10	13.3	8.3	9.0	10.5	12.0	12.8	13.7	15.1	15.6	16.9	18.3
13.8kV Normal Capacity (ONAF):			39.9	25.1	26.6	28.3	30.0	31.1	32.1	33.7	34.4	36.0	37.6
13.8kV N-1 Contingency Capacity (ONAF):			26.6	25.1	26.6	28.3	30.0	31.1	32.1	33.7	34.4	36.0	37.6

Exceeds transformer ONAN rating
Exceeds transformer maximum ONAF rating

As shown in Table A13 - 7, the MS331-T2 transformer will exceed its normal 10 MVA ONAN rating in 2020 and will exceed its maximum 13.3 MVA rating in 2023 during the summer peak following the completion of the planned residential developments. The table also illustrates that the 13.8kV system in Alliston will exceed the system contingency capacity across substation transformers in 2019 upon the loss of a transformer at either MS330 or MS331.

The new substation will provide 10 MVA of 13.8 kV capacity from 2018 to 2027 for the commercial and residential developments. The new substation will also provide contingency backup capacity for the Alliston system upon loss of MS331-T1 or MS331-T2, thereby satisfying the planning criteria for N-1 contingencies.

The Alliston station project consists of purchasing land in the vicinity of Industrial Parkway west of Tottenham Road and the construction of a new 10 MVA, dual-stage fan, 4-feeder substation which includes engineering design, purchase of station equipment, approvals, substation construction, equipment installation, and commissioning.

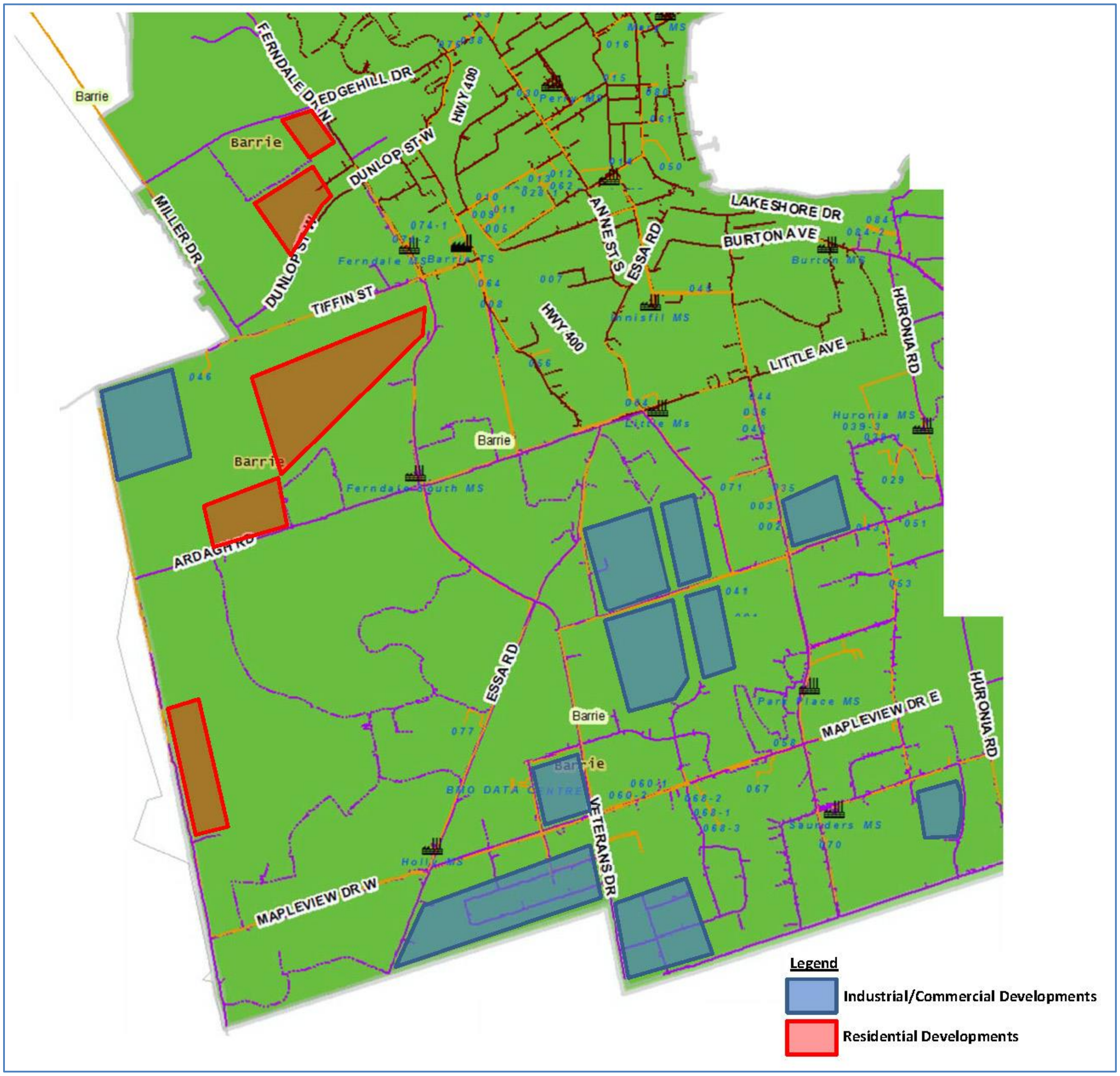
3.2.3 Barrie – New 20MVA Municipal Substation

During the DSP period, Alectra Utilities expects that the demand from forecast residential and Industrial/Commercial developments in Barrie will exceed the utility's capacity. Alectra Utilities plans to build a new 20 MVA MS to supply this growing demand. This station will allow the utility to relieve the load on current station and to provide backup required in N-1 contingency situations. Without the planned MS, Alectra Utilities would be unable to supply the forecast load growth or to satisfy the N-1 contingency standard, meaning that customers in this region would either not be able to connect or would be exposed to unacceptably high reliability risks. Alectra Utilities forecasts expenditures of [redacted] on the land purchase and design and preconstruction for a new station during the DSP period.

South-west Barrie is currently supplied by five 13.8 kV municipal stations: MS302, MS303, MS305, MS308, and MS307. The first four substations have each a 20 MVA transformer with dual-stage fans with ONAN and ONAF ratings of 26.6 MVA and 33.2 MVA respectively. MS307 is a 10MVA substation with dual-stage fans with ONAN and ONAF ratings of 13.3 MVA and 16.6 MVA respectively.

Growth projections provided by the City of Barrie indicate that 2,120 residential units and approximately 26 MVA of industrial and commercial developments will be completed over the next ten years. The projected developments in the City of Barrie are illustrated in Figure A13 - 2.

Figure A13 - 2: City of Barrie Proposed Developments



Following the completion of these developments, MS305, MS308 and MS303 are projected to exceed ONAN ratings during summer peak in 2020, 2021, and 2023 respectively. Also, MS305 and MS308 will exceed single-stage fan ONAF ratings during summer peak in 2023 and 2027 respectively. The ten-year load growth projection is provided in Table A13 - 8.

Table A13 - 8: Barrie 10-Year Load Growth Projection

Station Information					Barrie 10 Year Load Growth Projection (MVA)									
Station ID	Station	ONAN Rating (MVA)	ONAF Rating (MVA)	ONAF/ONAF Rating (MVA)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
MS303 (13.8 kV)	Ferndale South	20	26.6	33.2	17.7	17.9	18.0	18.2	19.3	20.2	22.0	22.9	23.9	24.8
MS305 (13.8kV)	Holly	20	26.6	33.2	19.2	19.8	21.2	23.2	25.3	27.3	27.8	28.3	28.8	29.3
MS308 (13.8 kV)	Park Place	20	26.6	33.2	13.7	15.0	18.1	21.9	24.4	24.8	25.3	25.7	26.2	26.7
MS307 (13.8 kV)	Huronia	10	13.3	16.6	7.3	7.6	7.8	8.1	8.3	8.5	8.6	8.8	8.9	9.1
MS302 (13.8 kV)	Saunders	20	26.6	33.2	13.3	14.0	15.3	16.7	18.0	19.3	19.6	20.0	20.4	20.7
13.8kV Normal Capacity (ONAF):				149	71.1	74.3	80.4	88.1	95.3	100.1	103.3	105.7	108.2	110.7
13.8kV N-1 Contingency Capacity (ONAF):				116	71.1	74.3	80.4	88.1	95.3	100.1	103.3	105.7	108.2	110.7

Exceeds transformer ONAN rating
Exceeds transformer single-stage ONAF rating
Exceeds transformer maximum ONAF rating

As shown in Table A13 - 8, the MS305 transformer will exceed its normal 20 MVA ONAN rating in 2020 and will exceed its single-stage ONAF rating of 26.6 MVA in 2023 during the summer peak following the completion of the planned developments. MS308, MS303 and MS302 will exceed the normal 20 MVA ONAN rating in 2021, 2023 and 2025 respectively. The ability to transfer load from MS303 to MS301 is limited due to there being only one existing feeder interconnection between both substations. Voltage drop issues would also arise in load transfer scenarios, given the long 7.1 km distance between MS303 to MS301. Voltage drop can cause significant issues for industrial customers, since equipment in a facility can trip due to low voltage resulting in outages and lost productivity. To mitigate these conditions, Alectra Utilities could be forced to limit the connection of new load.

In recent years, load transfers have been carried out from MS305 to MS308; however, any additional transfers to MS308, coupled with the new load from ongoing commercial developments, will contribute to MS308 exceeding its ONAF single-stage fan rating of 26.6 MVA.

The new 20 MVA substation will provide up to 33.2 MVA of 13.8 kV capacity (dual-stage fan ONAF/ONAF configuration) to supply the industrial and commercial development along Bryne Drive, Big Bay Point Road, and Mapleview Drive over the next ten years, as well as capacity for 2,120 new residential homes in South Barrie. The new substation will provide capacity relief to both MS305 and MS308, while providing backup supply to the neighbouring substations under contingency conditions. This will ensure compliance with the planning criteria for single contingency (N-1) operations.

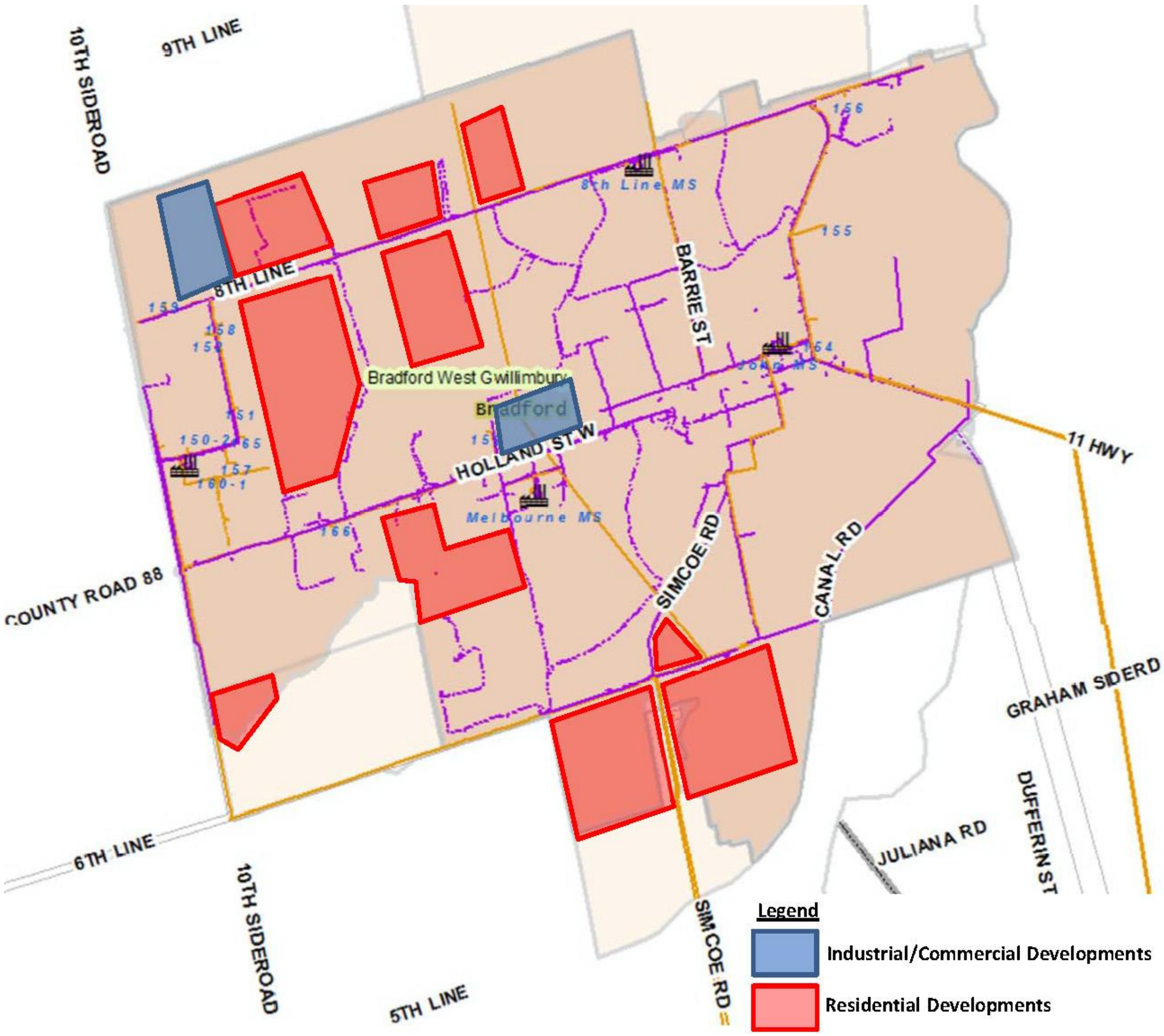
3.2.4 Bradford - Melbourne MS322 Land Purchase and Transformer Upgrade

During the DSP period, Alectra Utilities expects that the demand from forecast residential and Industrial/Commercial developments in Bradford will exceed the utility's capacity. In these investments, Alectra Utilities plans to purchase the property that the Melbourne MS322 substation is built on, and to upgrade from the current 10 MVA transformer with a 13.3 MVA maximum rating to a 10 MVA transformer with a higher 16 MVA ONAF/ONAF maximum rating. These investments will provide sufficient supply to meet the expected growth in the region and to maintain backup required to address N-1 contingency situations. Without the planned transformer upgrade, Alectra Utilities would be unable to supply the forecast load growth or to satisfy the N-1 contingency standard, meaning that customers in this region would either not be able to connect or would be exposed to unacceptably high reliability risks. Alectra Utilities forecasts expenditures of [redacted] in 2019 on the land purchase and $1.35MM on the transformer upgrade during the DSP period.

Currently, Bradford is supplied by four 13.8 kV MS: MS323 (8th Line), MS322 (Melbourne), MS321 (John) and MS324 (Reagans). Each substation has a 10 MVA single-stage fan transformer with a maximum transformer ONAF/ONAF rating of 13.3 MVA.

As shown in Figure A13 - 3 below, growth projections from the Town of Bradford indicate that 1,960 residential homes will be completed, along with industrial and commercial developments along 8th Line, Langford Boulevard, and Professor Day, over the next ten years.

1 **Figure A13 - 3: Town of Bradford Proposed Developments**



2

3 As a result of the proposed developments, MS324 and MS322 ONAN ratings will be exceeded
4 during summer peak loading in 2019. The developments will also result in the contingency
5 capacity for the Bradford 13.8 kV system being exceeded in 2024 upon loss of a substation
6 transformer. The ten-year load growth projection for Bradford is provided in in Table A13 - 9.

Table A13 - 9: Bradford 10-Year Load Growth Projection

Station Information				Bradford 10 Year Load Growth Projection (MVA)									
Station ID	**Station**	**ONAN Rating (MVA)**	**ONAF Rating (MVA)**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
MS321 (13.8 kV)	John	10	13.3	4.8	4.9	5.0	5.2	5.3	5.4	5.4	5.5	5.6	5.6
MS322 (13.8 kV)	Melbourne	10	13.3	9.7	10.3	10.6	11.2	11.8	11.9	12.0	12.2	12.3	12.5
MS323 (13.8 kV)	8th Line	10	13.3	8.4	8.6	8.8	9.0	9.2	9.3	9.5	9.6	9.7	9.8
MS324 (13.8 kV)	Reagans	10	13.3	10.7	11.1	11.4	11.7	12.0	12.5	13.0	13.1	13.3	13.4
13.8kV Normal Capacity (ONAF):			53.2	33.6	34.9	35.9	37.1	38.3	39.1	39.9	40.3	40.8	41.3
13.8kV N-1 Contingency Capacity (ONAF):			39.9	33.6	34.9	35.9	37.1	38.3	39.1	39.9	40.3	40.8	41.3

Exceeds transformer ONAN rating
Exceeds transformer maximum ONAF rating

Table A13 - 9 illustrates that the MS324 transformer exceeded its normal 10 MVA ONAN rating in 2018 and will exceed its maximum 13.3 MVA ONAF/ONAF rating in 2026 during the summer peak following the completion of the planned developments. The MS322 transformer will exceed its normal 10 MVA ONAN rating in 2019. The table also illustrates that the 13.8kV system in Bradford will exceed the system contingency capacity across substation transformers in 2024 if one of the transformer at any of the four 13.8kV substations.

The project expenditure consists of purchasing the leased land at Melbourne MS322 and eventually upgrading the existing transformer from a 10 MVA unit with a maximum ONAF rating of 13.3 MVA to a new 10 MVA transformer with a maximum ONAF rating of 16 MVA. Upgrading the transformer includes: engineering design; purchase of station equipment; approvals; substation construction; equipment installation; and commissioning.

The proposed upgrade to a 10 MVA transformer with 16.6 MVA maximum loading capability will ensure capacity for the 1,960 new residential homes in south Bradford, as well as the 13.8 kV component of the industrial and commercial developments at 8th Line, Langford Boulevard, and Professor Day over the next ten years. The upgraded substation transformer will also provide contingency backup capacity for the Bradford 13.8 kV system upon loss of an adjacent substation transformer during summer peak loading, thereby ensuring compliance with the applicable planning criteria for single contingency operations.

In addition, Alectra Utilities plans to purchase the property on which the Melbourne MS322 is built. Alectra Utilities currently leases the land at Melbourne MS322 from the Town of Bradford. The lease agreement expires October 30, 2020. The Town of Bradford is expanding the existing fire hall adjacent to Melbourne MS322 to include a new police station and additional parking. The Town originally intended to terminate the Melbourne MS322 land lease agreement thereby forcing Alectra Utilities to decommission MS322 and purchase land in an alternate location; however, land availability in the immediate area is extremely limited and distant parcels would require extensive 13.8 kV integration work. Alectra Utilities met with Bradford Planning Staff to identify the importance of maintaining the existing substation have established an understanding to negotiate a land purchase so as not to relocate the station and feeders which would include significant expenditures. The valuation for the land is based on analysis of similar properties in the area.

3.3 Central Stations Investments

3.3.1 Background: Development of Downtown Mississauga

As set out in Sections 3.3.2 and 3.3.3 below, Alectra Utilities plans to construct a new MS to serve downtown Mississauga during the 2020 to 2024 DSP period. This subsection summarizes the expected growth and intensification in Mississauga's downtown core that drives the need for the new stations.

The downtown core of Mississauga began to develop in 1973 with the construction of the Square One Shopping Centre, as shown in Figure A13 - 4. At that time, the Downtown Core consisted of little more than Square One and large amounts of vacant farmland. Square One has undergone many expansions over the past four decades, during which time Mississauga's downtown core has seen an increase in high-rise residential and office development.

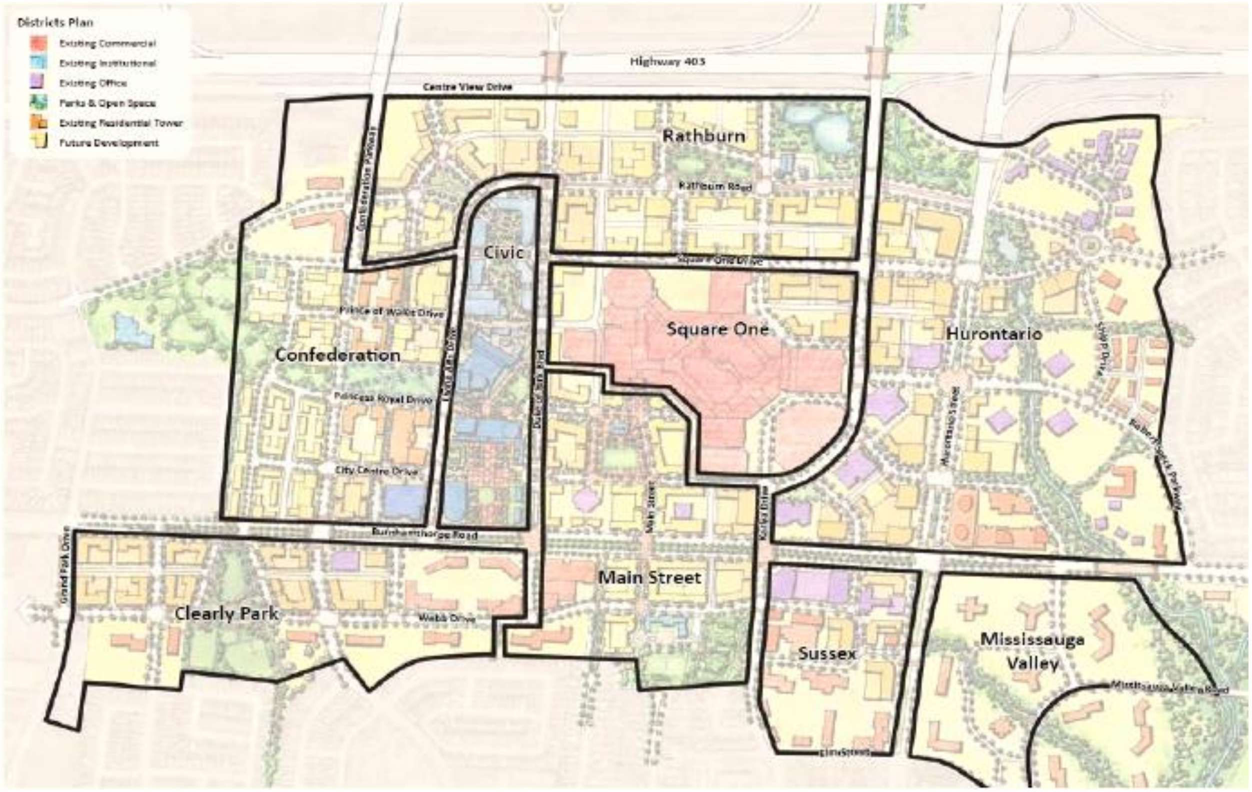
Figure A13 - 4: Square One Shopping Centre in 1973 and 2018

Today, the downtown core is the focus of the urban growth in Mississauga and houses the City's cultural and institutional centres, as well as being a regional centre and major transportation hub for the Greater Toronto Area. The core contains the Civic Centre, the Living Arts Centre, the Central Library, the YMCA and Kariya Park. Additionally, this area is comprised of a mix of office buildings and high-rise residential apartments focused around the retail, commercial development within and around Square One. Recently, the Downtown Core has seen the emergence of Celebration Square, the completion of the new Sheridan College Campus, new commercial development along Rathburn Road and improvements to the Light Rail Transit (LRT) and Bus Rapid Transit (BRT) terminal.

The City of Mississauga has issued an official plan called "Downtown21" which sets out expected growth and intensification in nine districts across downtown Mississauga.[126] The Downtown21 plan forecasts a total population of 56,565 residents and 34,247 jobs in the downtown core. The City establishes and maintains a long-term plan for these planning districts, including road systems and land use development.

[126] "Downtown21: Creating an Urban Place in the Heart of Mississauga" by Glatting Jackson Kercher Anglin, April 2010. Accessible from: http://www6.mississauga.ca/onlinemaps/planbldg/images/DT21/Downtown21_FINAL_2010-04-08_web.pdf

Figure A13 - 5: Down Town Planning Districts

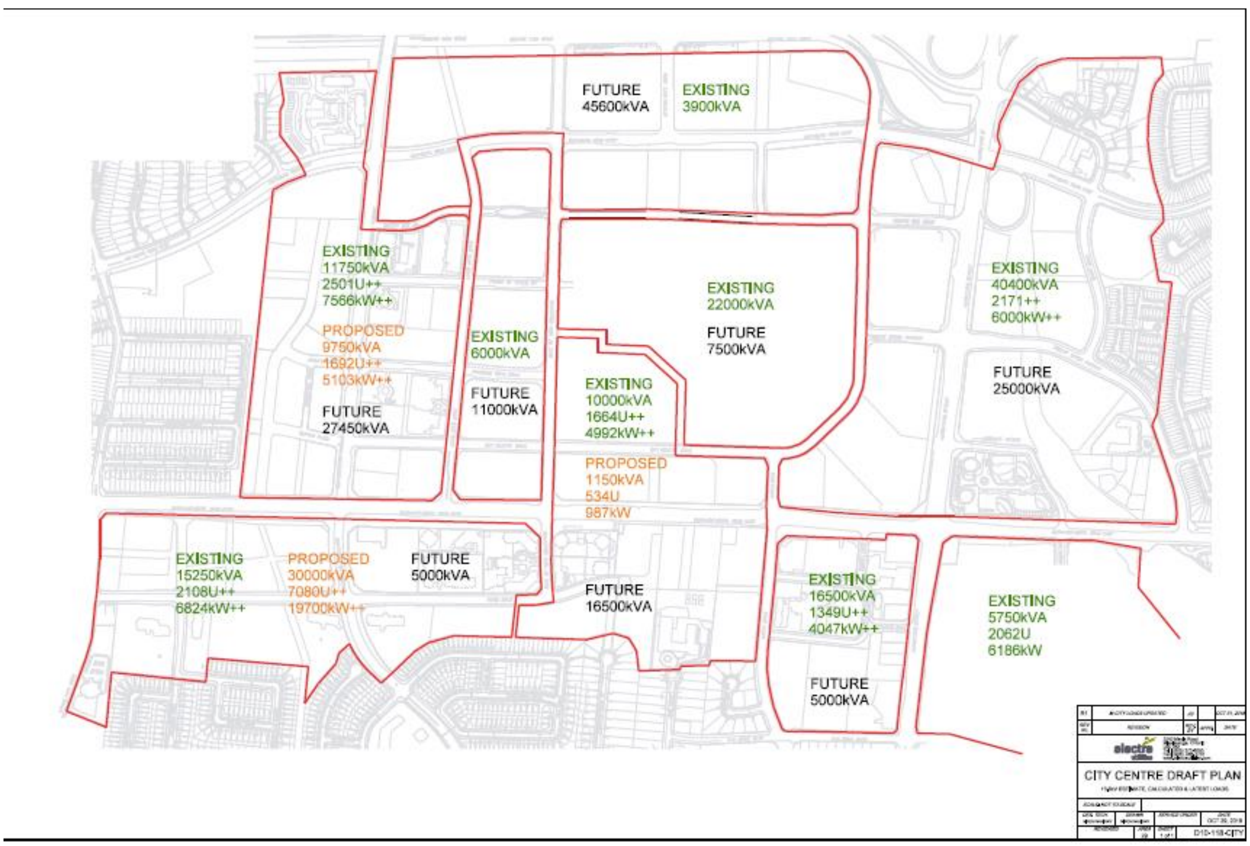


Currently, there are approximately 65 buildings in the downtown core and three substations: Woods MS, Confederation MS, and City Centre MS. These substations are equipped with either two or three power transformers, and most of their capacity is dedicated to supplying the existing load in the downtown core. Further, John MS, located on Hurontario Street near John Street, also provides power to Mississauga Valley and Sussex districts. The current capacity available for the downtown core is approximately 140 MVA ONAN rating. Based on growth projected and the land parcels available, Alectra Utilities estimates that, upon completion of Downtown21 in 2035, the combined transformation load requirement will increase approximately by 300 MVA. Alectra Utilities will have to expand its infrastructure in the downtown core and increase the number of substations to reliably supply additional load. At least eight substation transformers will need to be dedicated to meet this significant future demand, including in contingency conditions.

Two new sites will need to be purchased for the construction of future Duke MS and Webb MS substations during the DSP period. During the DSP period, Alectra Utilities plans to obtain land for Duke MS. Alectra Utilities expects that associated feeder egress work will be start in 2023 and station will be energized in 2024. Webb MS lands will be purchased in 2019 and station will be constructed as the load materializes. This land purchase is necessary as there will be no parcels left as large scale developments continue to happen in the downtown core.

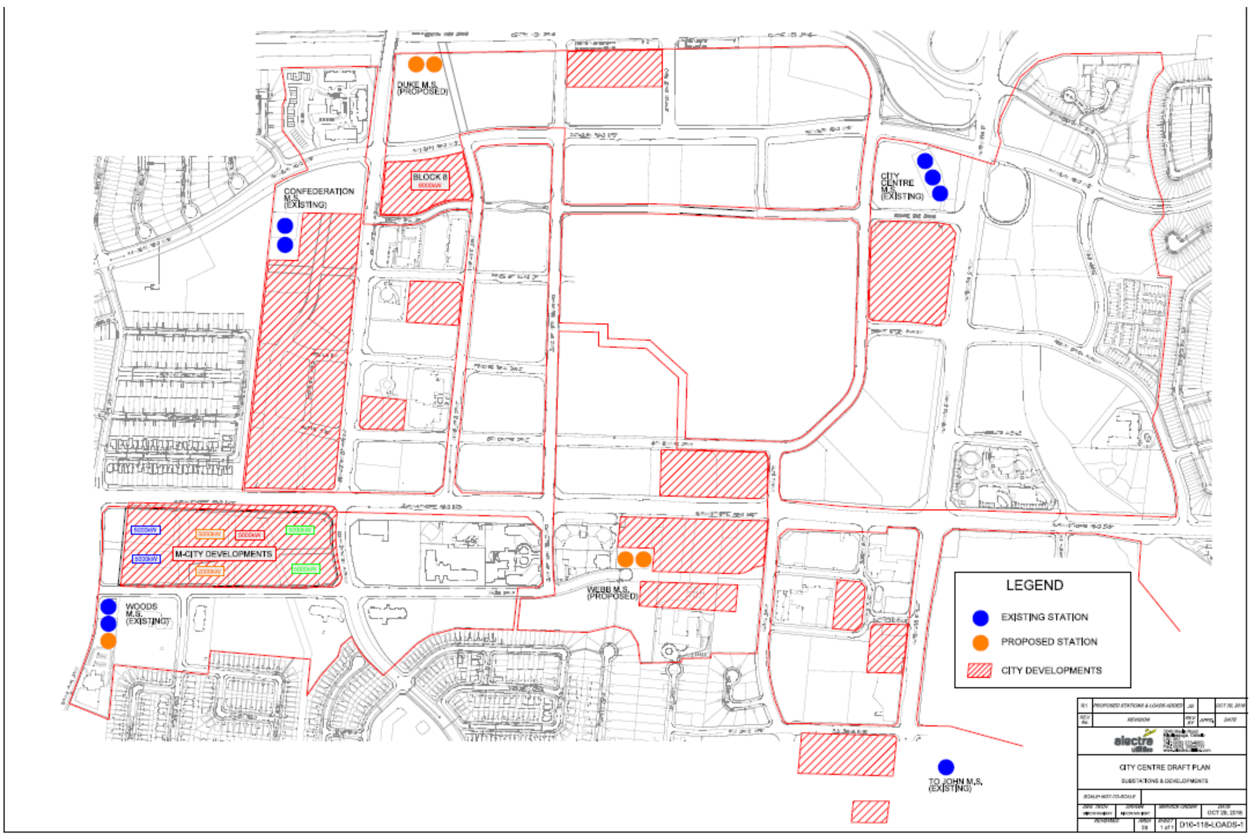
Figure A13 - 6 shows the existing and forecast electricity demand in each of the City planning districts. Where available, the loads have been projected based on applications that specify the number of units or commercial space that will be available. The loads for other buildings, where such information is not available, have been estimated based on the type of building, the approximate building footprint, and the number of floors. In cases where no information regarding future buildings is available, the load for the area is based on a load of a similar area that was completed in the past.

Figure A13 - 6: Present and projected demand in Downtown21 Planning Districts



In order to satisfy the expected demand resulting from the growth and intensification of the downtown core, Alectra Utilities determined that it must install new transformers at two new substations in the northern and southern parts of the downtown core. Based on careful review and consideration of the existing feeder locations, future development and locations of the existing substations, Alectra Utilities determined that the optimal location for the northern substation is near the intersection of Centre View Drive and Duke of York Boulevard. (Duke MS), and the optimal location of the second substation is near the intersection of Webb Drive and Kariya Drive (Webb MS). The specific plans for Duke MS are set out in Sections 3.3.2 . Figure A13 - 7 shows the existing and proposed station sites in the downtown core.

Figure A13 - 7: Existing and Proposed Location of Downtown Core Substations



Known Large Developments

There are two known large developments planned for Mississauga that drive some of the need for stations capacity expenditures during the DSP period. Both are summarized below.

Block 8 and Office Towers along Centre View Drive

Block 8 is bounded by Rathburn road to the North, Confederation to the west, Living Arts to the East and Square One Drive to the South. The parcel will consists of 6 buildings in total ranging from 40 stories to 54 stories with total 18MW of load which includes 3MW of electric vehicle charging load by 2026. Alectra Utilities is currently working on the design for Phase 1 which consists of 2 towers (896 units) with total load of 6 MVA. In addition, there are planned office towers along Centre view drive and Rathburn which will another 10 MW of load. Alectra Utilities has received application for development of Office tower which will add another 3 MW of load on Centreview and Station Gate.

Rogers (M-City)

The Rogers M-City[127] will transform a vacant 15-acre lot at the South West corner of Burnhamthorpe road. This development is projected to house some 6,000 residents and will consist of 10 towers 60-75 stories and will add another 30 MW of load. Phase 1 which is designed consists of 2 building with total of 5MW. Alectra Utilities has been notified of the Phase 2 which is of similar size.

[127] http://urbantoronto.ca/database/projects/m-city

Figure A13 - 8: M-City Master Plan

3.3.2 Duke MS - New 20MVA Municipal Station

As summarized in Section 3.3.1, Alectra Utilities determined that a new MS would be required in the northwestern region of Mississauga's downtown core. Alectra Utilities has determined that the optimal site for that MS would be the proposed Duke MS site at Centre View Drive and Duke of York Boulevard. Alectra Utilities forecasts expenditures of $6.2M on the Duke MS during the DSP period.

Alectra Utilities is currently finalizing coordination with Oxford Properties for a land swap arrangement to enable the development of Duke MS. Alectra Utilities owns lands in proximity to Hurontario Street, that is being swapped for lands required for Duke MS. Alectra Utilities is further coordinating with the City road expansion of Living Arts Drive with the installation of civil duct structure in 2019.

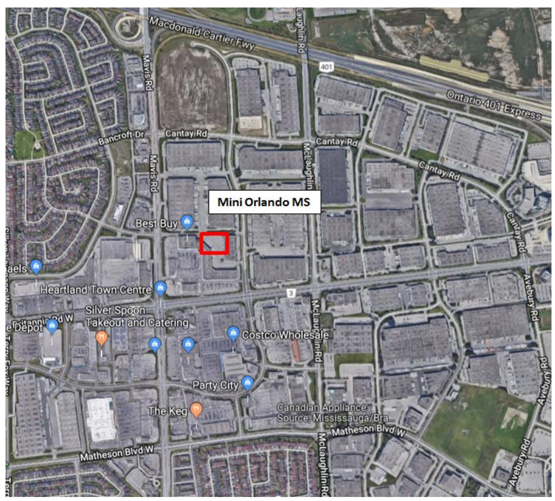
Confederation MS currently supplies the region where this development is planned. Due to capacity and feeder egress limitations, Confederation MS cannot supply the new development. The feeders currently present will not be able to supply the newly proposed load

Based on the timing of the new development Block 8 the new Duke MS will need to be in service by the summer of 2025.

3.3.3 Land Purchase for Mini-Orlando MS

Mini-Orlando MS is situated on leased land in the area of Mavis Road, south of Highway 401, provides capacity for the commercial and industrial customers in the Heartland area. Based on the analysis set out below, Alectra Utilities forecasts the value of this property to be [redacted].

Figure A13 - 9: Location of Mini Orlando MS



The Heartland Town Centre is an outdoor shopping centre located in Mississauga. Heartland Town Centre occupies 2,200,000 square feet of space and has 180 stores, making it is one of Canada's largest malls. The Heartland Town Centre is serviced by 27.6 kV supply.

Mini-Orlando MS was specifically built to supply the Heartland Town Centre, since the nearby Erindale TS did not have sufficient capacity to supply the development. Although Erindale TS supplies both 44 kV and 27.6 kV service, the station's 27.6 kV supply is overcapacity, while its 44 kV supply had available capacity.[128] Since Erindale TS could not supply 27.6 kV capacity, the Mini-Orlando Station was constructed to transform the available 44 kV of Erindale TS to 27.6 kV

[128] During the regional planning effort with Hydro One and other participating utilities, including Alectra, it was determined that Erindale TS T1/T2 was expected to remain over-loaded above the 10-Day Limited Time Rating (LTR) during summer peak, and that over-capacity should be addressed through available transformation capacity adjacent to the limiting assets.

to feed the Heartland Town Centre, and to off-load capacity from the 27.6 kV supply at Erindale TS.

Mini-Orlando MS can accommodate transfer from Erindale TS 27.6 kV feeders and meets the capacity requirement of the industrial/commercial customers of the Heartland Town Centre-area. During the 2017 peak, Mini Orlando shed 13 MVA from the Erindale TS which was still over the LTR limit. In the absence of Mini-Orlando, Alectra Utilities would be unable to supply the Heartland Town Centre load as Erindale 27.6 kV is already over the its rated capacity.

Given its importance to the area, Alectra Utilities has determined that it would be imprudent to continue leasing the land on which the Mini-Orlando MS is built. There is limited availability of land in the area, and it would not be possible for Alectra Utilities to secure land to move the Mini Orlando MS. Purchasing the property from the current owner would eliminate the capacity risk and cost associated in the case where Alectra Utilities was required to relocate the station (assuming it were possible to find another site for the station). Alectra Utilities plans to purchase the leased property.

3.4 Investments in Non-Wires Alternatives

As set out in Sections 3.1.1 Table A13 – 3, York Region is one of the fastest growing regions in Ontario. Provincial policies, including the Places to Grow Act and the Greenbelt Act, have played a key role in facilitating and driving development in this region. While a large portion of the land in this region is part of the designated Greenbelt area and is protected from urban development, the 2005 Places to Grow Act has promoted rapid intensification and development in specific designated urban areas surrounding and south of the Greenbelt. Extensive urbanization in these areas over the past decade has resulted in continued increase in electricity demand. In 2017, York Region had an electricity demand peak of over 2000 MW. Under the updated province's Places to Grow Act 2017, significant population growth and intensification are expected to continue in York Region in the coming decades.

Over the last few years, Alectra Utilities has continued to engage with municipalities in York Region to confirm projected growth, discuss the near-term need for a new transformer station and associated distribution and/or transmission lines in the Markham-Richmond Hill area and to discuss at a high-level the medium- and longer-term planning activities in York Region.

NWA are Distributed Energy Resources (i.e. generation, storage, load management) used to manage local peak demand and other services to defer or avoid capital and operating costs associated with distribution infrastructure.

In order to better understand the extent to which non-wires solutions can be used to help manage the electricity demand growth in York Region in the medium to longer term, Alectra Utilities' will deploy NWA solutions to assess their value in deferring and/or avoiding infrastructure investments. Such solutions will help provide Alectra Utilities with understanding to enable more efficient and reliable system incorporating NWA solutions.

As is stated in the 2017 Long-Term Energy Plan, "Energy storage can offer benefits throughout the grid, from large-scale facilities that can reduce the need to build new supply, import electricity or use GHG-emitting generation sources, to smaller-scale devices that can provide backup services to buildings."[129] This is consistent with Alectra Utilities' customer engagement feedback relating to implementing new technologies that can give customers more choices, improve reliability or reduce the impact on the environment.

The Long-Term Energy Plan makes-reference to two studies on energy storage that were completed at the request of the Ministry of Energy: (i) a 2016 IESO study on energy storage; and (ii) a 2017 study published by Essex Energy Corporation.

The IESO study, "IESO Report: Energy Storage," was produced following a request from the Ministry of Energy in April 2015. This study presents the many benefits of energy storage to the bulk electricity system. Among the benefits the report identifies is the deferral of system upgrades through the use of energy storage to reduce local system peaks.[130] The report states:

> "Energy storage could also help improve the utilization of existing transmission and distribution assets by deferring some costs associated with their upgrades or refurbishments, as well as improve the quality of electricity supply in certain areas of the system by controlling local voltages."[131]

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[129] 2017 Long-Term Energy Plan, Ministry of Energy, 2017, p.60
[130] IESO Report: Energy Storage, Independent Electricity System Operator, 2016, p.5
[131] IESO Report: Energy Storage, Independent Electricity System Operator, 2016, p.35

Essex Energy Corporation's 2017 study, "The Study of Energy 1 Storage in Ontario's Distribution Systems," was requested by the Ministry of Energy in March 2016. The report describes a number of benefits of energy storage, including distribution system upgrade avoidance, new generation capacity avoidance, redundant power supply (reliability), and power quality improvement.[132] In one of its case studies, the report also identifies the enablement of renewable generation as another benefit of energy storage.[133]

The 2018 "Removing Obstacles for Storage Resources in Ontario" IESO report presents the many benefits of energy storage and IESO's commitment in supporting new technology. The report states, "Enabling innovation and competition of newer technologies is central to the Independent Electricity System Operator's (IESO's) innovation and efficiency agenda. Because energy storage can deliver multiple capabilities – both as a load and as a generator – supporting further integration of these resources into the electricity system is essential to sector evolution and modernization."[134]

3.4.1 Non-Wires Alternative Project

Alectra Utilities plans to evaluate the operational effectiveness of DERs deployed across the service area as a NWA solution, in order to defer and/or avoid distribution infrastructure investments. With the assent of Bill 87, *Fixing the Hydro Mess Act, 2019*, the Ontario government modified conservation and demand management (CDM) program funding from a local distribution delivery model to a centralized delivery model administered by the IESO. As a result, Alectra Utilities will wind down the delivery of conservation and demand side management solutions. Due to the uncertainty of the effectiveness of the centralized delivery model to focus on specific localized areas with known capacity related issues, Alectra Utilities proposes to explore other non-wire alternative solutions to reflect Alectra Utilities priority for energy management solutions as identified in the 2018 placement customer engagement.

Alectra Utilities will evaluate DERs across a large service area which will provide a platform to aggregate, measure and test the impact of widespread implementation of DERs such as solar

[132] The Study of Energy Storage in Ontario's Distribution Systems, Essex Energy Corporation, 2017, p12
[133] The Study of Energy Storage in Ontario's Distribution Systems, Essex Energy Corporation, 2017, p27
[134] Removing Obstacles for Storage Resources in Ontario, 2018, p2

generation and battery storage units as a Virtual Power Plant ("VPP"). This project will also assess the opportunity to increase operational efficiency and improved asset management to enhance service to customer and defer and/or reduce infrastructure investment needs in York Region. Alectra Utilities will also explore the opportunity to aggregate and bid DERs into the wholesale market to provide additional energy services, which would positively impact their business case.

The expected benefits of the NWA project include:

- System planning and business process development to enable Alectra Utilities to utilize widespread DER deployment across Alectra Utilities' service area as a feasible non-wires solution to defer distribution infrastructure needs.
- Enhance coordination, communication, and interoperability between Alectra Utilities' distribution system and IESO's transmission system
- Potential to reduce overall system costs by achieving local, targeted feeder performance improvements to defer the need for conventional infrastructure upgrades.
- Emerging sector interest in developing regional or distribution-level markets to enable DERs to provide local system needs.
- Provide customers with increased flexibility to make decisions about their electricity consumption, generation, and costs.
- Evolution of the distribution system to permit more efficient integration of DERs to yield greater benefits to customers, system reliability, and power quality.

IV Investment Timing and Pacing

4.1 Summary of Expenditures

Table A13 - 10 provides the year-over-year breakdown of the Stations Capacity investments, including the historical period from 2015-2018, the bridge year in 2019, and the DSP period from 2020 to 2024.

Table A13 - 10: Historical and Proposed Investment Spending

	Historical Expenditure				Bridge	Forecast Expenditure				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	17.0	17.6	10.3	2.4	2.7	0.8	0.8	0.8	5.2	12.0

4.2 Historical Expenditures (2014-2019)

Historical expenditures between 2015 and 2019 total $50MM. These expenditures included necessary capacity upgrades, including station expansion efforts in these years.

The expenses in 2015 to 2019 were mainly related to new Transformer Station (170MVA) capacity built in the Vaughan and a 20MVA station in Barrie and 40MVA station in Mississauga to support load growth. The investments in 2019 are related to land purchases for new station in Bradford and Mississauga.

4.3 Future Expenditures (2020-2024)

Future expenditures from 2020 onwards to 2024 will total $19.6 MM. These expenditures are primarily driven by land purchase and new substation construction and capacity upgrades at existing stations. There are no Stations Capacity investment needs in 2020, and hence there is no expenditure. Investment in 2021 and 2022 is mainly related to non-wires alternatives project while investment in 2023 and 2024 is related to land purchase and station construction in Alliston, Barrie and Mississauga and Class EA for TS in Markham. These investments have year over year fluctuations because Alectra Utilities plans the station investment based on load growth and contingency capacity requirements, and not on recurring patterns of spending.

Table A13 - 11: 2020-2024 Projects and Expenditures

Project Code	Description	Expenditure ($MM)				
		2020	2021	2022	2023	2024
101570	New Alliston 10MVA Substation - 44 kV Supply				0.018	0.339
101571	New Alliston 10MVA Substation - 13.8 kV Feeder Integration				0.035	0.637
101569	New Alliston 10MVA Substation - Industrial Parkway				[redacted]	1.062
150319	New MS - Duke MS 20 MVA Substation, Mississauga				1.953	4.200
101488	Markham TS #5				0.272	0.447
100459	New Barrie 20MVA Substation - Harvie - 44 kV Supply					0.004
100461	New Barrie 20MVA Substation - Harvie - 13.8kV Feeder Integration					0.029
150367	Mini-Orlando MS 27.6kV Land Purchase, Mississauga					[redacted]
101542	New Barrie 20MVA Substation - Harvie				[redacted]	1.369
150332	Non-Wires Alternative Project	0.771	0.787	0.819	0.829	0.838
102455	Melbourne MS322 Land Purchase & TX Upgrade - Bradford				0.437	0.916

4.4 Investment Pacing and Prioritization

Alectra Utilities uses a "deterministic" approach in planning the station capacity. A deterministic planning methodology means that in a contingency situation all of the station load can be backed by another station in the planning zone.

Alectra Utilities' annual load forecast reflects historical load patterns and expected service growth based on regional, municipal and customer long-term plans. It also accounts for other influences and factors such as CDM and distributed generation programs and rate pricing structures, weather correction or large anticipated loads that are known to Alectra Utilities.

The station land purchases and construction are based on the load growth and taking into account future CDM/DG contributions and coincide with known and forecasted development.

The NWA investments are required to be implemented now so that Alectra Utilities can prepare the distribution system to safely and reliably respond to the expected uptake of DERs.

Customer Engagement Outcomes:

Alectra Utilities conducted a second phase of customer consultation in early 2019. The objective of the second consultation was to identify customer preferences between the outcomes of particular investment options, to inform the prioritization of specific investments in the DSP. The second round of customer preference indicated that customer in the Alectra East operating zone preferred lower spending on stations capacity project. Alectra Utilities has incorporated the identified customer preference by deferring the Alliston MS from an initial in-service date of 2023 to 2025. Alectra Utilities plan to manage the station deferral by closely monitoring the load, focus on connecting the industrial customers on the 44KV network rather than the 13.8KV network and implementing non wire/ CDM initiatives.

4.5 Execution Approach

Alectra Utilities will utilize internal and external contractors to complete the design and construction of the stations. The Execution phase will follow Alectra Utilities' internal project management methodology which provides specific guidelines, procedures, work instructions, and industry best practices that allow the project work to be performed in an economically efficient, cost-effective, and safe manner.

Alectra Utilities has standardized the design for the TS and MS and has experience in completing the station projects. The most recent example is the completion of 170MVA DESN station in Vaughan and completion of 20MVA station in Barrie on-time and on-budget.

V Options Analysis

Alectra Utilities has considered different options for each component of the Stations Capacity portfolio, as detailed below.

5.1 *Status Quo*/ "Do Nothing"

There is insufficient capacity on the system to meet the load growth and the contingency requirement in each of the project areas identified herein, and therefore the Status Quo option is not recommended. Alectra Utilities has also examined the risk of not securing land for the relevant stations and determined that the pace of rapid development and increasing scarcity of suitable parcels (both regarding size and location) favour the timely acquisition of land in the DSP period. If this investment is deferred into the future, Alectra Utilities is likely to incur higher costs associated with the land purchase as well as significant 44 kV and 13.8 kV feeder integration costs.

5.2 Utilizing Non-Wire Alternatives

Alectra Utilities' load forecast process considers the impact of CDM and distribution generation, which is accounted for as part of the load forecast underpinning the Stations Capacity portfolio. Alectra Utilities has also considered other options, such as battery storage, and determined that these options will not meet the load growth and contingency conditions for the stations to be upgraded during this DSP period, however beyond the DSP period, could contribute to the deferral of investment. As described above, Alectra is currently increasing its capacity to develop and manage DERs that could provide more opportunity to use NWA in future DSP periods.

5.3 Other Wires Alternatives

Alectra Utilities has considered other wire alternatives, where ever feasible. The following sections provide the other wires alternatives that were evaluated.

5.3.1 New 10 MVA Substation – Alliston

Concerning the Alliston area, the first investment alternative that was considered consists of installing a new switch and extending the existing 13.8 kV feeder 800 meters westward. In the existing feeder configuration, 100% of the 13.8 kV component of Westerly ICI and Easterly ICI would be supplied by MS331-T2. Upon completion of the residential development east of 10th Sideroad, MS331-T2 will exceed its 10 MVA ONAN rating in 2020 and 13.3 MVA ONAF rating in 2023. Installing a new, normally open 13.8 kV switch along Industrial Parkway in front of the Westerly ICI development would result in 50% of the Westerly ICI load allocated to MS331-T2 and 50% to MS330. Extending the MS331-T1 13.8kV feeder westward 800 meters would transfer the Easterly ICI load from MS331-T2. The feeder reconfiguration would result in the MS331-T2 ONAN rating being exceeded in 2021 and defer exceeding the 13.3 MVA ONAF rating beyond 2027; however, the MS330 10 MVA ONAN rating would still be exceeded in 2026. Also, this alternative does not address the expected exceedance of the 13.8 kV contingency capacity in Alliston, therefore failing to meet the minimum planning criteria for N-1 operations. Accordingly, Alectra Utilities does not plan to pursue this option.

The second investment alternative consists of expanding 8th Avenue MS330 from 10 MVA to 20 MVA and adding two additional 13.8 kV feeders. Alectra Utilities rejected this alternative because the existing station is of the 1980 vintage and the building is too small to accommodate the required expansion.

5.3.2 New 20 MVA Substation – Barrie

As an alternative to the planned substation in Barrie, Alectra Utilities considered constructing three new 13.8 kV feeders for integration between MS302 to MS305, MS303 to MS301, and MS308 to MS303. The existing network configuration has only a single feeder integration between each respective substation, thereby limiting the transfer capacity during contingency conditions. Each proposed pole line is described below:

- <u>MS302 to MS305:</u> A new 13.8 kV feeder from MS302 is running north along Bayview Drive and then west along Mapleview Drive to reach Veterans Drive for integration with the existing MS305 13.8 kV feeders along Mapleview Drive.
- <u>MS303 to MS301:</u> Double circuit a new 13.8 kV circuit with the existing MS303-F3 north along Ferndale Drive to Sunnidale Road and then east along Sunnidale Road for integration with the existing MS301 13.8kV feeders.
- <u>MS308 to MS303:</u> A new 13.8 kV feeder from the intersection of Bayview Drive and Big Bay Point Road, west past the Highway 400 crossing to reach Veterans Drive and then

north along Veterans Drive to Ferndale Drive at Essa Road for integration with the existing MS303 13.8 kV feeders.

Performing load transfers between existing stations will result in approximately 75% loading at MS303 and MS305, with all adjacent stations being loaded at 80% or above. With additional load from nearby commercial developments, the substation loading will increase beyond 80%. Assuming that the load can be distributed between MS308, MS305 and MS302, Alectra Utilities expects that the ONAN rating at MS302, MS304, and MS307 will be exceeded by 2022. The projected cost for the additional feeders is $4M.

In addition to the construction cost estimate, this approach would also entail voltage level and line loss issues. The MS303 to MS301 feeder would be 7.3km, and the feeder end would experience a voltage level of approximately 13.22 kV with 400A of loading on the transfer feeder (MS303 is limited to a 420 A egress rating). The feeder section would also result in 115 kW of line losses, translating into approximately $51,000 of annual losses on the section. The three proposed 13.8 kV feeders would provide contingency transfer capacity and accommodate transfers to reduce loading at MS303 and MS305. However, given the possible addition of 20 MVA from the industrial subdivision zoning in the area, the three 13.8 kV feeders and subsequent transfers between substations would not be sufficient to address the expected exceedance of the substation ONAN and single-stage fan ONAF ratings in the area. For these reasons, Alectra Utilities rejected this option.

5.3.3 Melbourne MS322 Land Purchase and Transformer Upgrade – Bradford

Alectra Utilities considered retrofitting the existing substation transformer at Melbourne MS with single-stage or dual-stage fans to increase capacity or building a new 2x10MVA 4 feeder substation to replace the single transformer 10MVA substation.

In July 2015, Alectra Utilities initiated a study to determine if the existing equipment permits a retrofit of single-stage or dual-stage fans to potentially defer the construction of a new substation by increasing the contingency transfer capacity. The resulting feasibility report indicated that upgrading the existing transformer fans is not recommended because the allowable temperature rise of the winding insulation (65ºC) remains unchanged with the addition of fans. Also, a fan retrofit would not address the expiry of the existing land lease agreement with the Town of Bradford. For these reasons, Alectra utilities rejected this option.

The further alternative option for Melbourne MS would be to build a new 2x10 MVA, 4-feeder substation to replace the existing single transformer 10 MVA substation. The alternative 2x10 MVA option would cost approximately $8.8M, due to the additional transformer and system integration. The substantial cost of a new 2x10 MVA substation makes the single 10 MVA (maximum 16 MVA ONAF) transformer upgrade the most prudent option.

The selected investment option of purchasing the land currently leased from the Town of Bradford and upgrade the existing Melbourne MS322 transformer from a 10 MVA transformer with a maximum loading of 13.3 MVA to a 10 MVA transformer with 16.6 MVA maximum loading capability ensure capacity for the 1,960 new residential homes in south Bradford. The selected option also address the 13.8 kV component of the industrial and commercial developments at 8th Line, Langford Boulevard, and Professor Day over the next ten years. The upgraded substation transformer will also provide contingency backup capacity for the Bradford 13.8 kV system upon loss of an adjacent substation transformer during summer peak loading.

The purchase of lease land from the Town of Bradford also ensures that supply can be maintained to existing and future customers in south Bradford while eliminating costs associated with substation decommissioning, relocation, and lengthy feeder integration. Also, upgrading the existing 10 MVA transformer unit will ensure the substation footprint accommodates the Town of Bradford facility expansion.

5.3.4 Substation Expansions

Duke MS

Alectra Utilities considered the following alternatives to constructing the new Duke MS substation:

Confederation MS Expansion

Confederation MS has two transformers supplies the northern part of Mississauga's downtown core. The current property allows for the installation of a transformer and breaker lineup to increase the capacity at Confederation MS. However, the City of Mississauga has proposed an extension of Square One Drive to Rathburn Road, which will require a portion of the land to be used for the new road. The remaining substation property will then be too small to accommodate an additional transformer and the high voltage equipment associated with it.

City Centre MS Expansion

There are three 20 MVA transformers installed at the City Centre MS site where the existing infrastructure, including duct banks and switchgear, is fully utilized. The installation of any additional transformers and feeders will require a major reconstruction of the substation and the associated civil infrastructure. Also, new feeders coming out of the substation will have de-rated capacity due to main feeder cable congestion and restricted duct bank configuration. As a result, the installation of an additional transformer is not economical and does not meet the technical requirements needed to supply load in the downtown core efficiently.

John MS Expansion Alternative

The John MS site has sufficient space for the installation of an additional transformer. However, the new feeders coming out of the substation cannot be extended north to the downtown core unless a new, second pole line with four feeders is constructed along the west side of Hurontario Street from John MS to Burnhamthorpe Road. Considering future projects, including the LRT along Hurontario Street, Alectra Utilities determined that it will not be able to install a new pole line on the west side of Hurontario Street in addition to existing pole line on the east side.

The proposed land swap arrangement with the builder is the most economical option which ensures that site is secured for Duke MS and station to be constructed in 2023/2024 to supply the loads between Rathburn Road and Centre View Drive.

VI Investment Projects

The investments from 2020 to 2024 that form the Stations Capacity investments are included in Table A13 - 12.

Table A13 - 12: Material Projects and Initiatives

Project Code	Project Name	CAPEX ($MM)
101569	New Alliston 10MVA Substation - Industrial Parkway	[redacted]
150319	New MS - Duke MS 20 MVA Substation, Mississauga	$6.2
150367	Mini-Orlando MS 27.6kV Land Purchase, Mississauga	[redacted]
101542	New Barrie 20MVA Substation - Harvie	[redacted]
150332	Non-Wires Alternative Project	$4.0
102455	Melbourne MS322 Land Purchase & TX Upgrade - Bradford	[redacted]

Appendix A14 - System Control, Communications and Performance

I Overview

During the 2020 to 2024 DSP period, Alectra Utilities plans to renew several categories of equipment that control, monitor, and protect the core distribution system assets across the grid. Several of these critical systems are deteriorated and functionally obsolete, which negatively affects the reliability of Alectra Utilities' service to customers. In the case of monitoring equipment, Alectra Utilities expects to realize significant capital savings during the DSP term by the expanded use of equipment monitoring systems.

During the DSP period, Alectra Utilities plans to invest in the following control and communication systems each of which is discussed in greater detail in Section 2.1 below:

- **Monitoring Equipment:** By expanding the use of equipment monitoring systems in its substations, Alectra Utilities expects that it will be able to defer significant capital investments. During the 2020-2024 DSP period, Alectra Utilities plans to expand its use of systems to monitor the condition of the transformers in its substations in real-time (as opposed to periodic inspections). As noted in Appendix A09 - Transformer Renewal, Alectra Utilities expects that these investments will allow the utility to significantly reduce its capital expenditures on substation assets. These investments are discussed in Section 2.1.1.
- **Fault Indicator Equipment:** Alectra Utilities uses equipment called a fault indicator to identify and respond to outages. Fault indicators allow distributors to assess where the grid has failed and to quickly restore power to most affected customers. Some sections of Alectra Utilities' system do not have modern fault indicators, and some existing fault indicators are not functioning. During the 2020-2024 DSP period, Alectra Utilities plans to install or replace fault indicators across the system, with a focus on areas that will result in the greatest benefit to the system and to customers. These investments are discussed in Section 2.1.2.
- **Protection and Control Equipment:** Distribution substations rely on electrically-operated switches called relays to operate high voltage circuit breakers, to protect the station bus and other assets from faults and over-loading. Many of Alectra Utilities' current relays are deteriorated and functionally obsolete. Over 40% of Alectra Utilities' relays are in poor

condition and need to be replaced. By upgrading to modern, intelligent relays Alectra Utilities will improve reliability and create other benefits for the distribution system and for customers. These investments are discussed in Section 2.1.3.

- **Communication Equipment:** Alectra Utilities controls and monitors the distribution system and substation operations through a communication network that includes a range of hard-wired (e.g., fibre optic) and wireless equipment. Some elements of that communication system are approaching or at end-of-life, or otherwise unable to process the level of information generated by the increasingly automated and inter-connected grid. During the 2020-2024 DSP period, Alectra Utilities plans to replace and upgrade the wireless communications equipment in several regions and substations. These investments are discussed in Section 2.1.4.

The System Control, Communications and Performance portfolio also includes investments to address identified power quality issues at its stations. The main planned expenditure in this category is to install new capacitors at Kenilworth Transformer Station ("TS") to address power quality issues identified by the Independent Electricity System Operator ("IESO"). These issues must be addressed to remain compliant with market rules and regulations. These power quality investments are discussed in Section 2.2 below.

Alectra Utilities will replace deteriorated and obsolete communication and control assets with equipment that meets modern standards. In addition to addressing the failure risk issues with the legacy assets, this modern equipment will facilitate high speed communication between distribution system devices, enabling various service improvements for customers, including automated return of service in the event of an outage, via devices with intelligence, capable of detecting outages and operating switches automatically to restore service.

The investments planned in this portfolio will improve reliability, enhance safety at Alectra Utilities' stations, and mitigate cyber-security risks. The planned investments will enhance system reliability by adding intelligent devices capable of monitoring and detecting outages and initiating restoration of power. These investments will enhance safety, allowing Alectra Utilities to monitor substation assets in real time via sensors capable of identifying and recording potentially hazardous conditions such as high temperature or the presence of gasses. These systems will instantly notify the operations center of alarm situations, allowing controllers to react quickly.

Safety will also be enhanced from the installation of new system communication assets using modern technology capable of transmitting large volumes of data from smart devices installed on the power lines. This will provide system operators with enhanced capabilities to control devices on the distribution system and in substations. The communications language used by these modern systems include stringent defense capabilities and cyber-security measures capable of protecting Alectra Utilities' software and data from cyber-attacks.

Table A14 - 1 summarizes the investment, drivers and outcomes associated with this investment.

Table A14 - 1: Investment Subgroup Summary

	Historical Expenditure				Bridge	Forecast Expenditure				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$4.7	$1.7	$2.9	$3.1	$5.9	$6.6	$5.8	$4.7	$4.1	$2.8
Primary Driver:	Functional Obsolescence									
Secondary Drivers:	Reliability, Power Quality, Safety									
Outcomes:	Customer Value, Reliability, Safety, Cyber Security and Privacy, Efficiency									

II Investment Description

Investments made through this portfolio will enable Alectra Utilities to update the control and communications systems at the substation and distribution level, while also mitigating power quality issues across the system and improving fault detection capabilities. Most of the investments address deteriorated, or obsolete assets used to control and communicate with stations equipment, and some also address identified power quality issues at Alectra Utilities' stations.

The following subsections provide further details on the planned investments in each category.

2.1 Monitoring Equipment

During the 2020-2024 DSP period, Alectra Utilities plans to continue investing in transformer monitoring equipment at its substations. This equipment will provide the utility with real-time telemetry data on key performance metrics for these assets, allowing it to plan investment and maintenance activities with greater precision than is possible when relying on periodic asset inspections and extrapolated information.

Alectra Utilities plans to install the following types of monitoring equipment at its stations during the DSP period:

1. **Online Dissolved Gas Analysis ("DGA"):** Measuring the dissolved gasses in transformer oil is an invaluable tool in identifying and diagnosing DGA levels indicating a potential transformer failure as well as assessing the health of a transformer. The presence of dissolved gasses in transformer oil can be caused by the decay of insulating materials in the transformer, and can indicate not only the presence of an issue with a transformer, but also the severity of the risk. The proposed online (i.e., remote) monitoring equipment would provide Alectra Utilities with a real-time assessment of the level of dissolved gasses in stations transformers. In contrast, the conventional method to measure dissolved gas in transformer oil is to perform annual oil tests which are sent to a laboratory for analysis. The transformer could possibly suffer a failure between annual tests even if the previous results where favourable. Online DGA monitoring provides invaluable data to enable condition-based maintenance and also defers investment in the new transformers and maximizes asset utilization.

2. **Temperature:** Transformer overheating causes premature deterioration of a transformer's insulation. By monitoring transformer temperature, appropriate actions may be taken so as to help ensure operation within acceptable operating parameters.
3. **Leaks:** Transformer oil serves as an insulation medium as well as a coolant. Not only are transformer oil leaks a potential environmental hazard, but reduced oil levels can increase the risk of internal fault and impair a transformer's ability to maintain temperature within acceptable operating parameters. Monitoring for oil leaks serves to help to protect the environment and maintain transformer oil levels.

By deploying these monitoring solutions, Alectra Utilities will receive far more real-time telemetry data from both distribution and substation equipment. Real-time telemetry, such as online DGA monitoring, oil levels and temperature, allow the utility to proactively manage the performance of these substation assets through maintenance activities, and can ultimately be used to indicate when rebuilds or full replacements must be performed. Therefore, investments over the DSP period for Substation Renewal[135] have been significantly reduced when compared to historical expenditures, due to the availability of more extensive, real-time data from the planned monitoring equipment investments.

Over the DSP period, Alectra Utilities plans to invest approximately $6.2MM in substation monitoring equipment.

2.2 Fault Indicator Equipment

Alectra Utilities is obligated to maintain safe and reliable power to its customers. When a failure in the distribution system occurs, quickly identifying the location of the failure is paramount in order to restore service. Fault indicators are critical in reducing the scale and duration of power outages. During the DSP period, Alectra Utilities plans to install fault indicators where none previously existed and where existing devices are no longer functional.

Planned investments in this category consist of installing and replacing fault indicators on Alectra Utilities' distribution system to reduce fault locating time, thereby improving outage response and,

[135] Refer to DSP Appendix A08 – Substation Renewal

consequently, outage restoration times. The budget will allow for the installation of LED fault indicators at various locations in the system.

Alectra Utilities plans to install fault indicators the following types of circumstances:

- Locations where the installation would result in significant system benefit by reducing the time required to identify faulted sections of overhead or underground cables (e.g., at strategic locations on long overhead circuits, circuit interconnections, and on multi-connected underground cable systems). In some cases, fault indicators will be repositioned on overhead circuits experiencing multiple "unknown" outage events. This provides the ability to zero in on the zone experiencing outages and troubleshoot the root cause.
- Locations identified during inspections as having no fault indicators or obsolete/non-functioning fault indicators.
- Locations where crews will be performing other types of work, such as cable injection/replacement, and fault indicators can be easily installed.

Over the DSP period, Alectra Utilities plans to invest approximately $4.0MM in fault indicator equipment.

2.3 Protection and Control Equipment

The primary function of the protection and control system is to provide monitoring and protection of station equipment and control of circuit breaker open, trip and close functions. This function is extremely important because it protects equipment and people from high electrical current, or "fault current," that flows through the electrical system during a fault condition. A fault condition occurs when electrical equipment fails and when one or more electrical conductors short to one another or to ground.

Protection equipment consists of relays, remote terminal units ("RTU"s),[136] communication switches, controllers and computing platforms typically installed in a series of panels or in the low-

[136] An RTU is a microprocessor-controlled device that interfaces with physical system asset to the SCADA system by transmitting data used to monitor and control facilities. Modern RTUs possess improved functionality and are more robust than legacy equipment performing similar roles.

voltage compartments of switchgear cells. Protection and control components can also be found in control cabinets of outdoor switchgear and transformers.

Older station protection and control components have protective relays that have electromechanical mechanism or discrete solid-state components. Such relays require periodic recalibration and perform only the basic functions. Modern protection and control components are predominately microprocessor-based digital devices that are self-regulating and do not require periodic re-calibration. These relays can be maintained at a lower cost, due to the reduced mechanical and moving parts. These relays possess wider and continuous setting ranges, along with improved functionality and accuracy, high-speed tripping and allow for storage and communication of a greater amount of data during a system fault event occurrence, including fault levels and oscillography data. Modern relays provide valuable fault and event record information for effective post event analysis, especially for transformer faults, and can also supply more complete fault information to System Controllers via the System Control and Data Acquisition (SCADA) system so that the utility can make more informed decisions.

The electromechanical and solid state relays currently installed at Alectra Utilities' substations are at or beyond their useful life. Critically, they are no longer supported by the original manufacturers and there is limited spare parts availability to continue to repair these assets going forward. Should those legacy relays fail, any outage would be of a prolonged time period due to the lack of spare parts and repair options. Moreover, certain microprocessor-based relays have reached their end of life and/or lack required functionality.

In order to address issues with protection systems, Alectra Utilities plans to upgrade protections at the following substations:

- Aurora MS6
- Markham TS#1
- Markham TS#2
- Markham TS#3
- Vaughan TS#1
- Richmond Hill TS#2
- Vaughan TS#1
- Vaughan TS#3

Alectra Utilities is making station protection upgrades at these and other stations in phases over a period of years, prioritizing systems with more urgent needs at each individual facility. Selection and prioritization of protection upgrade projects is based on the circumstances of each system and facility. Considerations include the criticality of the assets involved, obsolescence, needs for more advanced functionality and synergies with other work. Also considered in staging this work is available resources and outage coordination.

Station protection systems are categorized by the asset type that they are protecting. Alectra Utilities uses protection systems to isolate faults in transmission lines, stations transformers, the station bus,[137] and the distribution feeders that supply power to customers. In each case, the protection systems exist to initiate tripping of circuit breakers that isolate the relevant equipment from the rest of the power system during fault conditions and prevent the propagation of fault current, thus minimizing potential equipment damage and safety risk.

Over the DSP period, Alectra Utilities plans to invest approximately $11.2MM in protection equipment.

The following sections summarize the specific protection upgrade investments planned for each of the stations listed above.

1. Vaughan TS#3 Bus Differential and Overcurrent Protections Upgrade

This investment involves replacing obsolete, unreliable bus protection at Vaughan TS#3, located in the City of Vaughan on Rutherford Road, east of Huntington Road. Upgrades will improve protection reliability, will provide improved fault record information for effective post-event analysis and will also supply more complete telemetry to System Controllers enabling more effective decision making.

[137] In the case of station bus protection equipment, the planned upgrades will improve station protection, increase reliability, provide improved communication to System Controllers and provide fault recording capability. Improved communication may allow for improved system automation and provide more information to control room, such as monitoring the status of equipment and whether equipment is performing within tolerances so that controllers can make informed decisions. Fault recording capability will assist in determining the source or location and the cause of system events, such as asset failures.

2. Markham TS#3 230kV Line Protections Upgrade

This investment involves replacing obsolete, unreliable line protection at Markham TS#3, located in the City of Markham on Kennedy Road, north of Highway 407. Upgrades will improve protection reliability, will provide improved fault record information for effective post-event analysis, especially for transformer faults, and will also supply more complete telemetry to System Controllers enabling more effective decision making. The new relays will allow for more sophisticated protection schemes designed to prevent mal-operation due to blown input fuses. This scheme is a requirement for the station's connection to the 230 kV transmission grid.

3. MS Feeder Protection Upgrade - AMS6

This investment involves replacing obsolete, unreliable feeder protections at AMS6, located in the Town of Aurora on Bayview Avenue, south of Wellington Avenue East. The existing protection systems include ABB model DPU relays which are no longer supported by ABB and parts are difficult to obtain. The replacement relays will meet Alectra Utilities' current standards will provide improved fault record information for effective post-event analysis and will also supply more complete telemetry to System Controllers enabling more effective decision making.

4. Richmond Hill TS#2 Upgrade Bus, Line and Transformer Protections

This investment involves upgrading obsolete, unreliable line, bus and transformer protections at Richmond Hill TS#2, located in the Town of Richmond Hill on Highway 7, west of Bayview Avenue. Communication protocol at this station is obsolete and incompatible with the rest of Alectra Utilities' system. Repairs are difficult, support from the manufacturer is lacking and some parts are no longer available. Upgrades will improve protection reliability, will provide improved fault record information for effective post-event analysis and will also supply more complete telemetry to System Controllers enabling more effective decision making.

5. Aurora MS6 (AMS6) Transformer and Bus Protection Upgrade

This investment involves replacing obsolete, unreliable transformer and bus protections at AMS6, located in the Town of Aurora on Bayview Avenue, south of Wellington Avenue East.

The existing protection systems include ABB model DPU relays which are no longer supported by ABB and parts are difficult to obtain. The replacement relays will meet Alectra Utilities' current standards will provide improved fault record information for effective post-event analysis and will also supply more complete telemetry to System Controllers enabling more effective decision making.

6. Markham TS#2 Line Protections and HMI Upgrade - KDU-10 Replacement

This investment involves replacing obsolete, unreliable line protections at Markham TS#2, located in the City of Markham on Highway 48 at Major Mackenzie Drive East. The existing protections include Westinghouse model KDU-10 electromechanical relays which are obsolete and no longer supported by the manufacturer. Upgrades will improve protection reliability, will provide improved fault record information for effective post-event analysis, especially for transformer faults, and will also supply more complete telemetry to System Controllers enabling more effective decision making. The new relays will allow for more sophisticated protection schemes designed to prevent mal-operation due to blown input fuses. This scheme is a requirement for the station's connection to the 230 kV transmission grid.

7. Markham TS#3 Bus Differential and Overcurrent Protections Upgrades

This investment involves replacing obsolete, unreliable bus protections at Markham TS#3, located in the City of Markham on Kennedy Road, north of Highway 407. The existing protections include electromechanical and solid state relays which are obsolete; repairs are difficult and service is not readily available. Upgrades will improve protection reliability, will provide improved fault record information for effective post-event analysis and will also supply more complete telemetry to System Controllers enabling more effective decision making.

8. Markham TS#3 T1/T2 "B" Differential Protections Upgrade

This investment involves replacing obsolete, unreliable transformer protections at Markham TS#3, located in the City of Markham on Kennedy Road, north of Highway 407. The existing protections include electromechanical and solid state relays which are obsolete; repairs are difficult and service is not readily available. Upgrades will improve protection reliability, will provide improved fault record information for effective post-event analysis and will also supply more complete telemetry to System Controllers enabling more effective decision making.

9. Markham TS#1 Bus Differential and Overcurrent Protections Upgrades

This investment involves replacing obsolete, unreliable bus protections at Markham TS#1, located in the City of Markham on 14th Avenue, west of Markham Road. The existing protections include electromechanical and solid state relays which are obsolete; repairs are difficult and service is not readily available. Upgrades will improve protection reliability, will provide improved fault record information for effective post-event analysis and will also supply more complete telemetry to System Controllers enabling more effective decision making.

10. Markham TS#1 T1/T2 "B" Overcurrent Protections and HMI Upgrade

This investment involves replacing obsolete, unreliable transformer protections at Markham TS#1, located in the City of Markham on 14th Avenue, west of Markham Road. The existing protections include solid state relays which are obsolete; repairs are difficult and service is not readily available. Upgrades will improve protection reliability, will provide improved fault record information for effective post-event analysis and will also supply more complete telemetry to System Controllers enabling more effective decision making.

11. Vaughan TS#1 Bus Differential and Overcurrent Protections Upgrades

This investment involves replacing obsolete, unreliable bus protections at Vaughan TS#1, located in the City of Vaughan on Dufferin Street, south of Highway 407. The existing protections include electromechanical relays which are obsolete; repairs are difficult and service is not readily available. Upgrades will improve protection reliability, will provide improved fault record information for effective post-event analysis and will also supply more complete telemetry to System Controllers enabling more effective decision making.

12. Vaughan TS#1 T1/T2 "B" Differential Protections Upgrade

This investment involves replacing obsolete, unreliable transformer protections at Vaughan TS#1, located in the City of Vaughan on Dufferin Street, south of Highway 407. The existing protections include electromechanical and solid state relays which are obsolete; repairs are difficult as service is not readily available. Upgrades will improve protection reliability, will provide improved fault record information for effective post-event analysis and will also supply more complete telemetry to System Controllers enabling more effective decision making.

13. Markham TS#2 Bus Differential and Overcurrent Protections Upgrades

This investment involves replacing obsolete, unreliable bus protections at Markham TS#2, located in the City of Markham on Highway 48 at Major Mackenzie Drive East. The existing protections include electromechanical and solid state relays which are obsolete; repairs are difficult and service is not readily available. Upgrades will improve protection reliability, will provide improved fault record information for effective post-event analysis and will also supply more complete telemetry to System Controllers enabling more effective decision making.

14. Markham TS#2 T1/T2 "B" Differential Protections Upgrade

This investment involves replacing obsolete, unreliable transformer protections at Markham TS#2, located in the City of Markham on Highway 48 at Major Mackenzie Drive East. The existing protections include electromechanical and solid state relays which are obsolete; repairs are difficult and service is not readily available. Upgrades will improve protection reliability, will provide improved fault record information for effective post-event analysis and will also supply more complete telemetry to System Controllers enabling more effective decision making.

2.4 Communication Equipment

During the DSP period, Alectra Utilities plans to investment in the communications equipment that connect the utility's substations and distribution system equipment. This equipment allows Alectra Utilities to control distribution equipment that is connected by the SCADA system.

SCADA-connected devices are critical to the effective function of the distribution system. The SCADA system allows Alectra Utilities to remotely control, operate and monitor substation assets such as circuit breakers, and distribution assets such as padmounted switches and reclosers. This remote control and monitoring allows Alectra Utilities to sectionalize the grid, isolate faults, and restore power to customers in an outage. This infrastructure also enables the automation of the distribution and substation assets via Distribution Automation and Substation Automation, respectively.

Alectra Utilities plans to invest primarily in two communications systems, each of which is discussed below in more detail:

- **WiMAX Infrastructure:** Alectra Utilities will install WiMAX communication hubs in order to enable high-speed broadband communications support for overhead reclosers, SCADA-enabled padmounted switches, FIT monitoring data concentrators and ethernet-enabled revenue meters. It also plans to update existing communication systems at municipal substations to the WiMAX standard, thus providing improved communication support for substation equipment.
- **Fibre Optic Infrastructure:** Alectra Utilities plans to invest in two forms of fiber optic communications systems: (i) backup fibre optic lines to provide redundancy should one communications path fail; and (ii) replacement of obsolete and deteriorated connection points in the fibre optic network (called "SONET nodes") with modern-standard nodes.

WiMAX Infrastructure

Current communications technologies implemented at the substation and distribution level are nearing or past their end-of-life criteria and are now functionally obsolete. This includes existing critical alarm enunciator ("CAE"), RTUs, and schedule 4 type 4 ("S4T4") analog communications circuitry that is no longer supported by the original manufacturers and aligned to current standards. While these assets are capable of communicating real-time telemetry such as current, voltage and temperature, and also allow for control from the control room, information and control enabled through these assets is currently achieved through an existing SCADA viewer, and are not compatible with newer forms of operations technologies, including a centralized advanced distribution management system ("ADMS"), in which automation of assets for the purposes of isolation, switching and restoration activities can be performed automatically using a centralized interface. This ultimately represents a significant efficiency improvement for the utility, as power system controllers no longer need to perform these restoration activities manually, and can focus their attention on higher-risk issues that can impact grid performance at a micro level.

As part of this investment, Alectra Utilities will deploy new, improved and secure high-speed communication hubs that are compatible with the WiMAX standard, thus ensuring secure and stable communications between the control room, ADMS and the assets in question. These hubs will support stringent cyber-security features, including AES256 encryption, anti-spoofing and remote connection rejection. New Synchronous Optical Networking ("SONET") transport mechanisms will inherently scramble the transported data, thereby preventing data reconstitution by third-party intruders.

Fibre Optic Infrastructure

Fiber optic infrastructure is designed to maintain the communications network between substations and from the substation to the control. As part of this investment, new fiber optic infrastructure will be installed in order to provide contingency to the communications network should a failure occur.

An example of this is the proposed addition of an alternate fiber optic communications path to Aurora MS#4. Aurora MS#4 is the site of a major communications hub for Alectra Utilities Operations. Currently both the main and backup paths to this hub are within the same cable, running north up Dufferin Street and Bathurst Streets respectively, as illustrated in Figure A14 - 1. The risk is high that the connection to the Aurora MS#4 communications hub would be lost should a truck hit a pole on Dufferin or Bathurst. To reduce this risk, Alectra Utilities will install new fiber from a FOSC on Yonge St, north to Yonge St, West on Bloomington and North on Bathurst to Aurora MS#4, as shown in Figure A14 - 1.

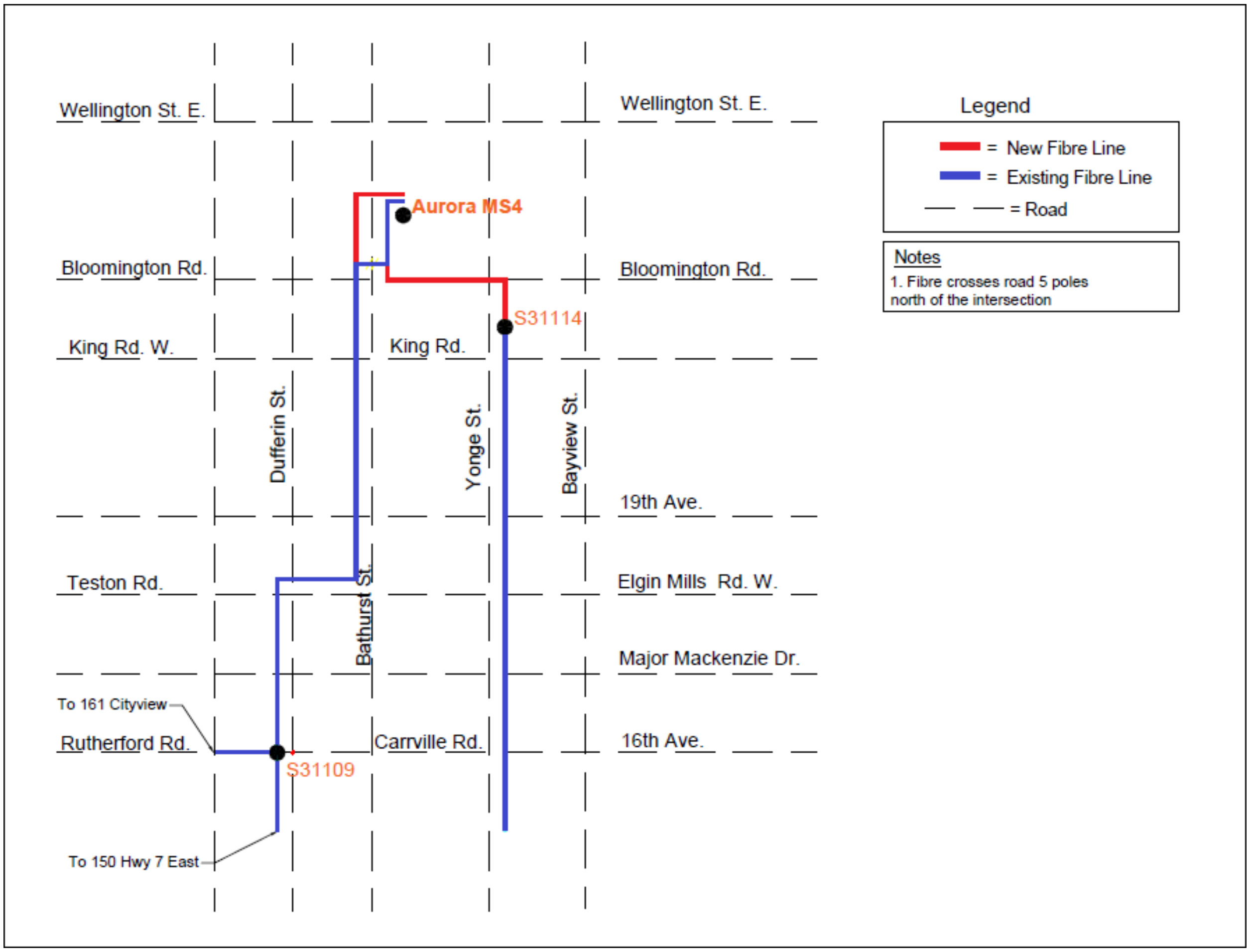
Once the redundant path is installed and functional, SONET and Communications shelf will be installed at Aurora MS#4. SONET, with its inherent cyber-security and the ability to quickly sense loss of communications and self-heal around the communications break, will further increase reliability by reducing the risk of communication loss and cyber-security breach.

Alectra Utilities relies on a high-speed self-healing OC-12 SONET fiber optic communications system to transport monitoring information, revenue metering and trip signals for protecting Alectra Utilities' critical assets. A SONET shelf is installed in each of Alectra Utilities' Transformer Stations and in other critical locations such as communications hubs, control room locations and Operations Centers. The shelf is made up of optical interfaces, control modules and equipment interfaces that connect to station's Ethernet LAN or to protection relays.

The existing OC-12 interfaces in the existing SONET shelves are at end of life. Alectra Utilities will implement a program to proactively replace these OC-12 interfaces with higher capacity OC-48 optical interfaces. The vendor has committed to supporting these OC-48 interfaces for a minimum of 15 years, Alectra Utilities has confidence that this critical communications system will remain in service and support additional growth as it has 4 times the capacity of the existing units.

Over the DSP period, Alectra Utilities plans to invest approximately $7.0MM in communications equipment.

Figure A14 - 1: Aurora MS#4 Location and Proposed Fiber Optic Path



2.5 Power Quality Equipment

Power quality issues can ultimately impact the performance of the system. Power quality refers to the ability of electrical equipment to consume the energy being supplied to it. A number of power quality issues including electrical harmonics, poor power factor, voltage instability and imbalance impact on the efficiency of electrical equipment. This has a number of consequences including:

- Higher energy usage and costs;
- Higher maintenance costs; and
- Equipment instability and failure.

An electrical utility's obligations include maintaining system voltages and power factor within certain parameters. Maintaining acceptable power factor levels serves to improve voltage regulation and reduce power losses.

In 2014, the IESO flagged Kenilworth TS as having poor power factor. Market Rules require that the connection applicant have the capability to maintain a power factor within the range of 0.9 lagging and 0.9 leading as measured at the defined metering points at the project facility. Alectra Utilities is addressing the IESO's request by installing power factor correction devices at this station. In order to respond to the IESO's requirements and to manage these performance issues, Alectra Utilities plans to install new 12 MVAR capacitors to correct the power factor at Kenilworth TS. The investments will be coordinated with Hydro One's plan to refurbish Kenilworth TS and will therefore take place in 2020. Power factor correction will be enabled through these investments at the TS level, impacted over 50 MVA of load.

Over the DSP period, Alectra Utilities plans to invest approximately $1.7MM in power quality-related equipment.

2.6 Summary of Investment Outcomes and Benefits

Table A14 - 2 summarizes the outcomes and benefits associated with the Underground Asset Renewal investment.

Table A14 - 2: Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Customer Value	• Most of the benefits of these investments deliver value for customers. • In addition to the benefits noted in other categories, this investment will mitigate power quality issues and concerns that have a direct impact on customers who are sensitive to such issues.
Reliability	• Replacement of legacy communications infrastructure will allow power system controllers to continue to isolate, perform switching and restore customers within a reasonable timeframe.
Safety	• The communications network is what allows the power system controllers to perform necessary isolation to the system, such that field crew workers can safely perform maintenance, repairs and/or replacement of assets.
Cyber-security and Privacy	• This investment will deploy communication platforms that are capable of stringent, defense in depth cyber security measures. All communications have inherent AES256 encryption. All platforms will participate with centralized authentication to prevent third-party intrusions.
Efficiency	• Real-time data delivered by the communications network will allow Alectra Utilities to continue to run their substation assets for a longer period of time, as enhanced predictive analytics can be performed to determine the optimal time for

Outcome	Investment Benefits and Objectives
	intervention. As such, investments within Substation Renewal have been reduced over the DSP period. • This investment will introduce operational efficiencies within the organization, enabling distribution automation and substation automation, which allow for switching, isolation and restoration tasks to be performed automatically without the need of controller intervention. • Automated logic can be implemented in these systems, allowing the local equipment to resolve first-order issues, freeing system controllers to address the root cause of an outage. • Modern standard switchgear contains high-speed relays which provide enhanced fault event recording, automation and control features. These features will enhance productivity in the control room while providing the utility with enhanced field intelligence in order to enhance decision-making

III Investment Drivers and Need

3.1 Purpose

As described above, the planned System Control, Communications and Performance investments are designed to replace critical system control and communications infrastructure that has reached its end-of-life criteria and are functionally obsolete. These assets manage the communication and control of substation and distribution assets that are used as part of sectionalizing, isolation and restoration activities. The drivers of this work are functional obsolescence, reliability, and power quality.

As the majority of the investment is focused on the need to replace infrastructure that is no longer supported, and lacks available spare parts, the primary driver of this work is functional obsolescence. Key operational functions that are executed by the control room, including isolation, restoration and switching activities, are largely dependent on the performance of these communications devices.

A secondary driver of these investments is reliability. Any failure at any point within the communications network would prevent power system controllers from performing necessary isolation, switching and restoration functions, and therefore would result in a greater magnitude of reliability and safety impacts. If a protection relay were to fail, the fault current would pass through the circuit breaker to the next upstream protective device, thereby significantly expanding the scope of the outage and potentially result in explosive equipment failure and risk to personnel.

Power quality is also a secondary driver of these investments. The planned expenditures are intended to mitigate the power quality issues and concerns for customers connected to Kenilworth TS. Capacitors will be installed to mitigate these issues.

Primary and secondary drivers are summarized in Table A14 - 3.

Table A14 - 3: Investment Drivers

Investment Driver	Reasoning and Investment Benefits
Primary Driver: Functional Obsolescence	As this investment is primarily replacing legacy infrastructure that no longer aligns to current Alectra Utilities standards and practices, and for which very few spare parts are available, these assets are considered to be functionally obsolete.
Secondary Driver: Safety	Protection of public and property is a secondary driver of this investment. Through the replacement of legacy end of life relays Alectra Utilities will ensure that station protection schemes remain fully functional and able to respond as intended to manage fault situations.
Secondary Driver: Reliability	Reliability is a secondary driver of this investment, due to the fact that system control and communication renewal allows for power system controllers to continue to safety operate the system and respond to outages within a reasonable timeframe. Failure of the communications network would result in prolonged customer outages.
Secondary Driver: Power Quality	Mitigating power quality issues for customers is another secondary driver, associated to the capacitor installation portion of the investments.

3.2 Legacy Control and Communications Infrastructure

3.2.1 Communications Hardware

Legacy control and communications infrastructure, including critical alarm enunciator (“CAE”) remote terminal units (“RTU”s), and schedule 4 type 4 (“S4T4”) analog communications circuitry, no longer align to modern standards and practices and are no longer supported by the original manufacturers. The communications assets addressed by the investments in this portfolio are functionally obsolete as they can no longer be sufficiently maintained and/or repaired. Furthermore, as the current legacy infrastructure does not contain high speed Ethernet communication ports, or support modern protocols such as distributed network protocol ("DNP") 3.0 or peer to peer communications capabilities such as Generic Object Oriented Substation Event ("GOOSE"), this equipment is not compatible with remote and automated control technologies, meaning that field crews must perform manual switching within these areas in order to perform adequate sectionalizing, isolation and restoration activities. Without communications upgrades, critical field data also cannot be returned to the control room, which can result in extended fault location activities and ultimately lead to the prolonged outages.

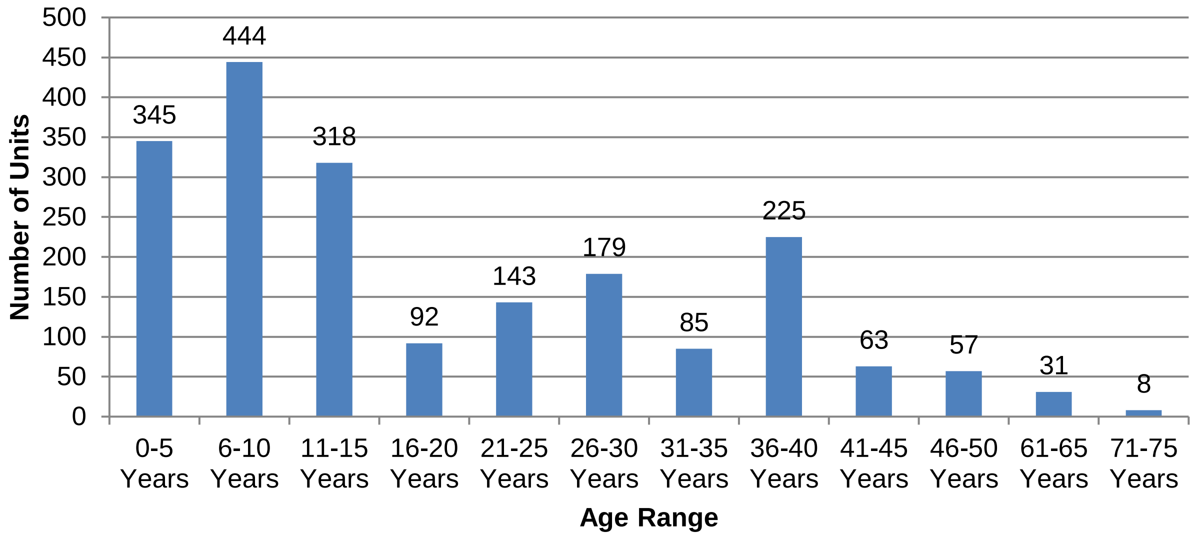
Should an existing legacy communications node fail, distribution assets will be unable to be remotely operable during an outage event, and field crews would have to be deployed to the location in order to manually perform switching and restoration activities. Ultimately, the outage restoration procedure will be much longer than it could have been otherwise. Execution of manual switching activities in general represents a safety risk for field crews, and is far more inefficient when compared to remote or automated switching activities.

Legacy RTUs are no longer manufactured by the original vendor and the hardware can no longer be repaired, due to the lack of spare parts, such as chipsets and electronic components on the circuit boards. These RTUs are limited to low-speed and serial communication protocols and are not suitable for the new communication technology. Ultimately, these RTUs introduce operational constraints for the power system controller, who will not have the necessary detailed information to know the exact location of the faulted asset. On average, four RTUs fail each year. Alectra Utilities expects that remaining spare part inventory will be fully exhausted in the next four years.

3.2.2 Protective Relays

Many of the protective relays in Alectra Utilities' fleet have exceeded their useful life and are both technically and functionally obsolete. The utility's vintage protection and control relays have electromechanical mechanisms or discrete solid-state components. 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 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. In comparison, modern protective relays are predominately microprocessor-based, digital devices that are self-regulating and do not require periodic recalibration. Figure A14 - 2 illustrates the current age demographics of Alectra Utilities' protective relay population. These results illustrate that approximately 13% of relays are beyond 35 years of age, which represents the useful life for electromechanical relays.

Figure A14 - 2: Age Demographics of Protective Relays



Electromechanical and solid state relays have, in general, exceeded what is considered to be their useful life and are both technically and functionally obsolete. Many are no longer supported by their manufacturer, repairs are difficult and parts are difficult of impossible to come by. These relays lack modern communications and fault recording capabilities that support high speed fault restoration and analysis

3.2.3 Fiber-Optic Communication Lines

The current configuration of the fiber optic communication lines lacks appropriate redundancy in some areas. Should the distribution system fail in these areas, critical substation infrastructure including circuit breakers and relays will be unable to sufficiently respond to the fault. If a fault occurs on the trunk portion of a feeder and the associated relay is unable to respond to the fault and trip the circuit breaker due to a lack of redundant communication lines, the fault energy will travel beyond the first protective device to the next protective device. At this level, the fault energy could trip the bus differential protection system, resulting in a far more substantial outage to a far greater number of customers.

3.3 Power Quality Issues and Concerns

Customers connected to Kenilworth TS continue to experience power quality issues and concerns, due to a power factor issue as a result of customer equipment. These customers were consulted upon to remediate the issue at their cost on multiple occasions, but their decision was to leave the utility to correct the issue at their level. Ultimately, correcting the power factor issue will mitigate some losses on the lines.

Power factor correction would improve the power quality for all other customers impacted on the TS bus. The customers causing the poor power factor will continue to pay higher energy costs as they are billed on kVA demand, which includes a component for poor power factor. This project must proceed in 2020 following Hydro One's plans to refurbish Kenilworth TS. Failure to address the issue would leave the power factor issue unresolved, which may lead to penalties from the IESO up to loss of Alectra Utilities' distribution license.

IV Investment Timing and Pacing

4.1 Summary of Expenditures

Table A14 - 4 provides the year-over-year breakdown of System Control, Communications and Performance investments, including the historical period from 2015-2018, the bridge year in 2019, and the DSP period from 2020-2024.

Table A14 - 4: Historical and Proposed Investment Spending

	Historical Expenditure				Bridge	Forecast Expenditure				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$4.7	$1.7	$2.9	$3.1	$5.9	$6.6	$5.8	$4.7	$4.1	$2.8

4.2 Historical Expenditures (2015-2019)

Historical System Control, Communications and Performance expenditures are based on Alectra Utilities' predecessor company's legacy practices. Historical investments in this category were based on different practices and utilized varying technologies available at the time. The increase in spend in 2019 is in part as a result of Alectra Utilities' initial investments and first steps to harmonize communication infrastructure, eliminate dependencies on third party service providers and to improve monitoring, control and communications capabilities for station assets. Alectra Utilities expects that the investments in monitoring equipment, when combined with Alectra Utilities Station Reliability Centered Maintenance practices, will allow the utility to better pace and prioritize, and, in some cases, defer substation renewal activities based on the telemetry offered through the investments in this portfolio. The average increase when comparing the historical period vs. the forecast period in in this category is approximately $1.1MM per year. This is offset by an average reduction in station renewals of approximately $3.2MM per year.[138]

[138] Planned Substation Renewal investments within this same period have been decreased when compared to historical investments, since Alectra Utilities expects that the investments in monitoring equipment will allow the utility to better optimize and, in some cases, defer substation renewal activities based on the telemetry offered through the investments in this portfolio. Alectra Utilities expects that better online monitoring will allow for better predictive analytics, thereby further optimizing when substation equipment should be maintained, repaired or replaced outright.

4.3 Future Expenditures (2020-2024)

Future expenditures will concentrate on restoring or improving performance of control and communications technologies as well as remediate power quality issues and concerns.

The increased expenditures from 2020 to 2023 are largely driven by the installation of communications hubs and monitoring equipment. As described above, Alectra Utilities expects that these expenditures will result in greater visibility of the substation equipment in particular, including real-time telemetry relating to temperature, oil quality and level and loading data. This information will allow Alectra Utilities to optimize stations capital investments and to better manage and predict the failure of substation assets. Proposed expenditures for control and communication infrastructure is driven by the need to replace the chipsets used in the OC12 optical interfaces. The vendor has advised that these units are at end of life and require replacement within two years. There is no anticipated future fluctuation in year to year spending.

4.4 Investment Pacing and Prioritization

Alectra Utilities will apply oversight and governance when it comes to the proper pacing and prioritization of these investments. Pacing of these investments will be aligned with other work planned for the same sites such that opportunities for bundling of work may be realized. Generally, control and communications projects are of a smaller scale suitable for agile implementation. Alectra Utilities does not foresee the need for complex planned outages.

Where planned outages are necessary, these projects will be executed quickly, and often at off-hours, so the impact to the system and customers is minimized. Project budgets have been created with this in mind.

4.5 Execution Approach

Alectra Utilities conducts formal project management, from developing investment scope details through to work execution. This ensures that investments are managed effectively throughout their project lifecycle and that adequate oversight is applied for change management. Formal processes are followed to initiate, plan, execute, monitor and control each investment within Alectra Utilities' portfolio of investments.

Alectra Utilities optimizes investments to align with financial and resource constraints and organizational capabilities. Alectra Utilities will utilize internal staff and external contractors to complete the renewals proposed for investments. Alectra Utilities has retained external contractors working at different work sites throughout the year under a multi-year Master Service Agreement to support Alectra Utilities' work requirements. This protects pricing and ensures resource availability from contractors.

For larger investments, the identification of project scopes are confirmed and formal designs typically commence one year in advance. This enables Alectra Utilities staff to perform investigative field analysis required to build comprehensive and thorough design products, with high quality material take offs and identification of and processing of external approvals, required for successful implementation of the work. Advanced designs facilitate allocation of long lead time items with sufficient lead time with the potential to capitalize on volume purchase agreements where possible.

For smaller investments such as those typically found with Station Control, Communications and Performance projects, internal employees are utilized and scheduled within the department resource allocations. If lines resources are required, the projects will be managed through the project management group as discussed below. Where specialized construction services are required external to the organization procurement of appropriate contracts will be sourced through Alectra Utilities Supply Chain processes and managed by the requesting department, e.g. Protection and Control, Substation Design or Substation Sustainment.

Alectra Utilities' internal project management methodology provides specific guidelines, procedures, work instructions, and industry best practices that allows work to be performed in an economically efficient, cost effective, and safe manner.

V Options Analysis

Alectra Utilities has considered different options for the execution of this investment, including the following:

- **Option 1"Status Quo" / "Do Nothing" option:** Take no action to replace existing system control and communications infrastructure or to manage power quality issues.

- **Option 2:** Replacement of legacy system control and communications infrastructure with Alectra Utilities-owned-and-operated infrastructure on a closed network, installation of capacitors in order to manage power quality concerns and station monitoring and protection upgrades in the 2020 to 2024 DSP period.

- **Option 3:** Implementation of system control and communications infrastructure leveraging a third-party network.

Alectra Utilities does not consider Option 1, "Do nothing" to be an acceptable approach, as reliability and functional obsolescence concerns would continue to persist moving forward. In the case of power quality, not establishing a solution would mean that Alectra Utilities is no longer complying with IESO regulations.

Option 3 is also not acceptable, since using a third-party communications network to control essential distribution infrastructure would present unacceptable risks to Alectra Utilities' ability to operate its distribution assets. Cellular networks are a publicly-used service, with a tremendous number of users, with the potential to be unresponsive (especially in major events where Alectra Utilities' ability to control the distribution system may be challenged by other environmental factors).

Option 2 is the optimal approach, as it replaces legacy system control and communications infrastructure, leveraging a dedicated communications network solely owned by Alectra Utilities and to be used exclusively for their assets. This option allows for standardized and modern control and communications technology to be implemented into the system. It allows for remote and automated control of distribution switch and station assets and station monitoring devices. The paced implementation of the investments over the 2020 to 2024 period will support improved monitoring of station power transformers, while providing improved substation protection scheme technology and capabilities.

With respect to power quality issues, the only viable option is the proposed investment: installing a 12MVAR capacitor bank which will be fully owned by the utility.

VI Investment Projects

The material projects and initiatives for System Control, Communication and Performance from 2020 to 2024 are included in Table A14 - 5.

Table A14 - 5: Material Projects and Initiatives

Project Code	Project Name	CAPEX ($MM)
150404	Kenilworth TS Power Factor Correction	$1.6

Appendix A15 - Safety and Security

I Overview

Safety and Security investments mitigate identified safety and security risks across the utility's distribution system that are not addressed through other capital portfolios.

During the 2020-2024 DSP period, Alectra Utilities plans to address three specific risks through these investments:

1. Public safety risks associated with undersized overhead conductors
2. Stations security system risks
3. Oil containment risks at Alectra Utilities' Municipal Stations (MS) and Transformer Stations (TS)

Alectra Utilities plans to address these risks through targeted investments. The legacy overhead conductors (#6 copper conductors[139]) have been identified as a public safety risk by the Electrical Safety Authority (ESA), which has requested that Alectra Utilities manage the risks. The utility plans to remove all such legacy overhead copper conductors from the system. All of these assets are in very poor condition and are undersized relative to load growth, and have a high probability of falling to the ground, thus posing significant safety risks to the public. These conductors will be replaced with standardized aluminum conductors and supporting equipment that are appropriately sized to load demands in the relevant areas. These expenditures also include the installation of substation security systems, including upgraded locks, video surveillance where gaps have been identified at specific stations. Finally, Alectra Utilities will install a Sorbweb oil containment systems at 106 Alectra Utilities' MS's where no oil containment systems currently exist.

[139] #6 is the conductor wire size (gauge) as defined by the American Wire Gauge Standard.

Table A15 - 1: Investment Subgroup Summary

	Historical Spending				Bridge	Forecast Spending				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$1.2	$0.1	$1.2	$0.9	$3.2	$5.4	$2.0	$2.0	$2.0	$2.0
Primary Investment Driver:	Safety									
Secondary Driver:	Reliability									
Investment Outcomes:	Reliability, Safety, Environment, Efficiency									

II Investment Description

This program targets those parts of Alectra Utilities' system that are currently exposed to considerable safety and security vulnerabilities, implementing required reinforcements and upgrades to address these vulnerabilities (and prevent potentially serious consequences from materializing) in an efficient and timely manner. As detailed below, this investment will target three key components of the system in particular:

- Legacy #6 overhead conductors;
- Municipal and transformer stations with security vulnerabilities; and
- Stations transformers without oil containment systems, with the potential to leak oil into the environment.

2.1 Installation of Standardized Overhead Conductors

Existing legacy #6 conductors and associated cross-arms pose significant public safety concerns. As discussed in Section 3.2 below, these wires are inherently weaker than other, higher diameter conductor, which has led to repeated instances in which live conductor have fallen to the ground. These assets also increase the risk of pole fires in some instances. These conductors are also under-sized relative to the current standard size conductors and in some cases undersized for current or potential future load, which further weakens the wires and accentuates the risk of failure. As such, there is a pressing need for their replacements with new standardized aluminum conductors, which will eliminate the aforementioned safety concerns and also be appropriately sized to supply current loads. More specifically, these conductors possess a larger diameter (and consequently, greater internal strength), and are more resilient to the external elements that can impact overhead lines, including severe weather events and tree or animal-related contacts. Since #6 conductors represent a significant hazard and the primary driver for investment is safety, the replacement is placed under System Service and not System Renewal. During the 2020-2024 DSP period, Alectra Utilities plans to invest $3.1M to address the risks posed by these conductors by eliminating 5 km of #6 conductor.

2.2 Security Reinforcement at Municipal and Transformer Substations

As a critical component of Alectra Utilities' distribution system, substations are responsible for transforming electricity to voltages levels that are suitable to be used for distribution purposes.

Stations can be the targets of physical sabotage and thefts, due to the valuable assets contained within the stations, such as copper metals that provide grounding capabilities. Stations which receive these investments will be selected based on a security audit. During the 2020-2024 DSP period, Alectra Utilities plans to invest $0.8 MM to address the risks posed by these conductors.

Within this program, Alectra Utilities will target those substations that are particularly vulnerable to security intrusions by installing the necessary security reinforcements, including Systems With Intelligence (SWI) “smart” video security systems to provide video monitoring capabilities. This security system will be “substation hardened” to withstand the rigorous demands of continuous reliable operations within substation environments.

Station physical security monitoring and recording provide important benefits:

1. Enabling surveillance by System Control to ensure safe equipment operations
2. Remote monitoring of work in progress at station
3. Triggering an alert in the event of abnormal entry to station premises
4. Monitoring of stations during severe weather events (flooding, damage assessment, etc.)
5. Monitoring of animal/bird intrusions at stations to minimize animal contacts

As part of the security monitoring system, cameras will be strategically located throughout the relevant substations, providing visibility of the indoor space, basement, switchgear, outdoor bus and structure, gates, fence/compound, transformers and switches, and capacitor banks. The strategic placement of cameras will maximize Alectra Utilities’ capability to identify all possible physical security threats and risks outside and inside the substation environment. Cameras will have pan-tilt-zoom capabilities to allow for remote adjustment from the control room. Additional required system hardware will include a digital video server, designed to record footage from multiple camera units (over 30 days of surveillance can be stored) and incorporate analytical algorithms and network capabilities that allow for advanced monitoring on a 24/7 basis to be streamed to Alectra Utilities’ control room. Once installed, this security system will provide automated alarms and event notifications in order to reduce the need for continuous manual monitoring. In tandem with the server, new cameras will be installed at strategic locations in order to.

In addition, existing door cylinders and padlocks to substation compounds and yards will be replaced with the new Abloy Smart CLIQ system. This system utilizes a double-locking mechanism, based on a combination of mechanical and electronic technology, such that physical keys can be administered to specific users and each user will have access using the assigned key at specific times, or for access to specific locks. Alectra Utilities' security administrators will be able to remotely manage this system.

2.3 Oil Containment Systems

As of January 2019, Alectra Utilities has 106 Municipal Stations (MS) that do not have oil containment systems. When the stations were put in service there was no requirement to install oil containment systems. Without the oil spill containment systems, leaks from the power transformers can result in severe environmental damages not only to the immediate substation site but also adjacent private or public properties. To migrate this risk Alectra Utilities plans to install Sorbweb oil containment systems.

The Sorbweb will surround the power transformer with a "gravity-based subterranean secondary oil containment system" using geosynthetic materials, which can trap oil in the event of catastrophic spills and leaks. The system incorporates a three-layer architecture, including a synthetic impermeable liner, an absorbent/adsorbent filter layer as well as a retention layer containing oil-absorbing fabric that seals on contact with hydrocarbons. This design does not require any sumps or oil water separators, and therefore eliminates the need for any regular maintenance activities. Please see Figure A15 - 1 for an image of the installation of the Sorbweb material.

Figure A15 - 1: Sorbwed Installation

The main driver of Alectra Utilities' planned investment in oil containment is public safety through environmental stewardship. By protecting customers from oil spills into water systems or onto their property Alectra Utilities is protecting from property damage and potential health issues. During the 2020-2024 DSP period, Alectra Utilities plans to invest $6.8 MM to install Sorbweb oil containment systems.

2.4 Summary of Investment Outcomes and Benefits

Table A15 - 2 summarizes the outcomes and benefits associated with the Safety and Security investment.

Table A15 - 2: Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Reliability	• Replacing existing undersized legacy conductors with standardized conductors (which are much less likely to fail, more resilient in withstanding external impacts, and possess higher load carrying capacities) will allow Alectra Utilities to meet current and projected customer loads with fewer outages.
Safety	• Replacing legacy conductors that are subject to a high risk of falling will minimize significant public safety risks and potentially catastrophic consequences. • Substation security reinforcements will address several material risks to field crews and the public: o Deterring theft of copper from stations (such incidents introduce direct safety risks to the perpetrators, as well as field crews performing any operational or maintenance work associated with the affected assets. o Preventing unauthorized intrusions, to eliminate direct safety risks to crews within the substation. o Preventing damage to substation assets resulting from security breaches (such incidents can elevate the risk of catastrophic failures, including fires/explosions and collateral damage to adjacent customer properties).
Environment	• New oil containment installed at MS locations will prevent oil leaks from leaching into the local environment, thereby mitigating any potential environmental risks or impacts.
Efficiency	• Replacing undersized legacy conductors with standardized conductor sizes will allow system controllers to be able to perform load transfer and restoration activities without being restricted by capacity limits.

III Investment Drivers and Need

3.1 Purpose

The primary objective of this investment is to target safety and security deficiencies within Alectra Utilities' distribution system, which, if not effectively mitigated, can give rise to serious consequences to jeopardize the safety of the public and Alectra Utilities employees (including field crews and substation maintenance personnel). As described in Section 2 above, the planning Safety and Security investments in the 2020-2024 DSP period target the following risks:

- Legacy undersized #6 overhead conductors
- Copper theft and intrusion within substations
- Lack of oil containment for specific MS power transformers

The secondary driver of this investment is reliability, due to the risk of outages associated with legacy undersized overhead conductors which are more prone to failure. These drivers have been summarized in Table A15 - 3.

Table A15 - 3: Investment Drivers

Investment Driver	Reasoning and Investment Benefits
Primary Driver: Safety	This investment is primarily driven by the need to address certain material safety risks to the general public as well as Alectra Utilities employees. These risks stem from: • The probability of downed wires due to the unacceptably low strength and current carrying capacity of legacy #6 conductors.[140] • Potential substation intrusions (and resulting dangers to field crew workers) if premises are not appropriately monitored and secured. • Indirect safety risks associated with damages to substation assets (due to copper theft or sabotage by intruders). • Potential oil contamination of soil or water due to lack of oil containment systems.
Secondary Driver: Reliability	A secondary driver of this investment is reliability. The program will address: • Enhanced risk of failure associated with undersized #6 conductor, which is no longer sized appropriately to current load levels. • Reliability risks stemming from potential damage to substation assets due to security breaches.

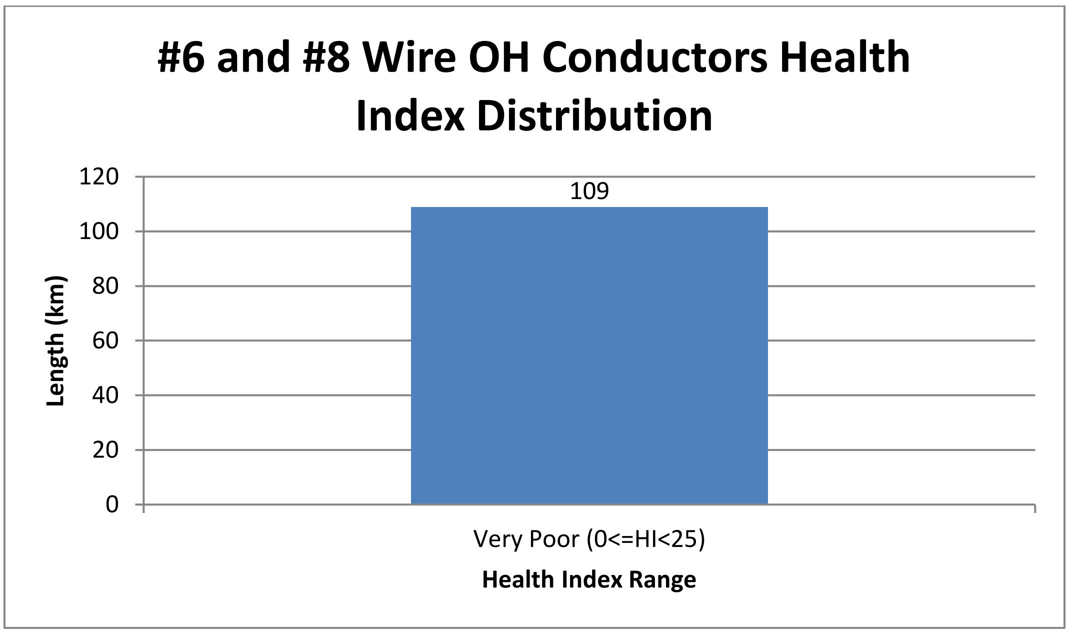
[140] Current above the rated capacity stresses and damages the asset depending on the amount and duration of the overload.

3.2 Undersized Legacy Overhead Conductors

In the last four years, there were four incidents of downed wires involving aging #6 copper conductors on Alectra Utilities' distribution system. In each case, a conductor segment dropped to the ground, creating an immediate safety risk to the general public. As a result, the legacy Horizon Utilities agreed with the Electrical Safety Authority to eliminate #6 conductors from its distribution system.

As shown in Figure A15 - 2, Alectra Utilities' asset condition assessment results confirm that all of the #6 and #8 copper conductors in Alectra Utilities' service area have reached their end of life.

Figure A15 - 2: Health Index- No 6 and 8 Conductor



In general, legacy overhead conductors introduce a number of performance-related issues, due to their smaller diameter, which inherently reduces the internal strength of the conductor spans. Given their constant exposure to external elements, including weather-related events (for example, high winds and ice storms), tree contacts and animal contacts, conductor spans must have a sufficient diameter and strength in order to be more resilient on a day-to-day operational basis.

Furthermore, these undersized conductors were installed long ago when customer loading was far lower compared to today's demands. Increased loading places these conductor spans at a heightened risk of exceeding their current carrying capacity, which can result in annealing, or reduction in the tensile strength of the conductor material, thereby further elevating the failure probability of the conductor span.

The limited current carrying capacity of these legacy conductors also introduces operational constraints for Alectra Utilities. Where an outage area contains smaller-sized conductors between the failed asset location and an available tie switch and feeder, power system controllers will have to account for the limited capacity on these conductors before executing the load transfer. If the required load transfer exceeds the limited capacity of that conductor span, then the controller must spend additional time finding an alternate route for load transfer. This results in an extended outage and may expand the scope of the outage until the failed asset is repaired or replaced.

This investment aims to eliminate and replace these undersized conductors with new standardized conductors that have been “right-sized” to the customer loading in the area and avoid limiting factors for power system controllers.

3.3 Substation Intrusion and Copper Theft

Substation intrusions and copper theft often go hand-in-hand, and pose significant safety and security risks. Copper is used to provide necessary grounding points for critical substation equipment. When these grounds are removed, this can introduce severe safety risks to substation crews in the course of executing maintenance procedures, as well as to those who might attempt to steal copper from Alectra Utilities’ stations.

There have been several incidents of copper theft at Alectra Utilities’ stations which required replacement of the ground grid. The most recent incident happened on Oct 29, 2018, at the transformer room at 151 Hughson Street South, where multiple ground wires/cables and a primary jumper were cut. The person who was attempting to steal the conductors suffered burn injury.

There is also the indirect risk of assets being damaged or even sabotaged during an intrusion event, which can accelerate the future failure of these assets. If the failure is catastrophic in nature, it will typically result in an explosion and/or fire at the substation level, endangering not only substation crews but also adjacent customer properties that could suffer significant collateral damages.

This investment aims to eliminate these security and safety risks, by installing enhanced electronic and physical security systems, including video surveillance and locking systems at stations identified under the security audit.

3.4 Environmental Hazards for Municipal Substation Transformers

A total of 106 of Alectra Utilities MS transformers do not possess the appropriate oil containment systems to contain oil leaks and spills, which can result in severe environmental damages not only to the immediate substation site but also adjacent private or public properties. These environmental hazards may also translate into safety hazards both for substation crews as well as the general public. At the time these transformers and stations were placed in service they met the required standards which did not require oil containment.

During the DSP period, Alectra Utilities plans to target these substation transformers and install new maintenance-free oil containment systems, thereby enhancing physical security and mitigating environmental risk at the substation. Alectra Utilities plans to install 20 oil containment systems per year at stations that will remain in service. Stations targeted by voltage conversion Alectra Utilities and will be decommissioned will not have oil containment installed.

Alectra Utilities will prioritize transformers based on a variety of risks including potential leaks, environmental impacts, the volume of oil, and the level of PCB. Over the last three years, two major spills have occurred, as well as several minor leaks. These spills and leaks signify that investment is needed, or Alectra Utilities will be forced to spend additional funds on clean up efforts that would be eliminated if containment was in place.

IV Investment Timing and Pacing

4.1 Summary of Expenditures

Table A15 - 4 provides the year-over-year breakdown of Safety and Security investments, including the historical period from 2015-2018, the bridge year in 2019, and the future period from 2020-2024.

Table A15 - 4: Historical and Proposed Investment Spending

	Historical Spending				Bridge	Forecast Spending				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$1.2	$0.1	$1.2	$0.9	$3.2	$5.4	$2.0	$2.0	$2.0	$2.0

4.2 Historical Expenditures (2015-2019)

Historical expenditures between 2015 and 2019 total $6.6 MM. These expenditures included both the replacement of undersized legacy overhead conductors as well as physical security reinforcements and oil containment systems at substations.

4.3 Future Expenditures (2020-2024)

Future expenditures from 2020 onwards to 2024 will total $13.4 MM.

Two of Alectra Utilities' predecessor utilities had not executed any projects relating to the installation of oil containment systems. This work is now planned throughout Alectra Utilities' distribution system, driving an increase in related and the costs. Oil containment accounts for 51% of the forecasted spending in the Safety and Security portfolio.

Expenditures in 2020-2024 reflect the cost of installing oil containment systems at substations throughout Alectra Utilities' operational areas, as well as replacing #6 conductor in high priority areas. These three main drivers of planned spending in this portfolio are oil containment (51%), #6 conductor replacement (23%) and station security (6%). Together, these three investment categories account for 80% of the forecast expenditures in this portfolio. The remaining 20% is primarily driven by two other investments. The first is ground grid installations for stations built before code requirements required them to be installed, similar to oil containment systems. The second investment is in secondary pedestals which are metallic, not fibreglass. These have a concern of touch voltage to the general public and are therefore being removed.

4.4 Investment Pacing and Prioritization

All of the #6 conductors in Alectra Utilities' service area have been identified through asset condition assessment as being in very poor condition. The areas selected for replacement under this program are the ones where there were no other renewal or expansion projects identified under this DSP (i.e. five priority areas were identified out of the 25 areas where #6 conductors are currently utilized.)

Alectra Utilities has several substations without an oil containment system. Two of Alectra Utilities' predecessor utilities had not initiated work to install oil containment systems, which is work that has been extended to all operational areas under this program. Stations with the highest risk and potential impact of environmental contamination are being prioritized under this program. Proximity to water, schools, residential dwellings, community spaces are factors considered determining pacing and prioritization as well as the condition of the transformers (i.e. to assess the risk of oil leaks).

4.5 Execution Approach

Alectra Utilities will leverage internal resources and external contractors to complete this investment, including the replacement of undersized conductors, security reinforcements at selected substations as well as installation of oil containment systems for existing MS power transformers.

Alectra Utilities has retained external contractors working at different work sites throughout the year under a multi-year engineering procurement construction (EPC) Master Service Agreement. Regular progress meetings are held to ensure technical and operational issues are resolved promptly.

The execution phase will follow Alectra Utilities' internal project management methodology which provides specific guidelines, procedures, work instructions, and industry best practices that allow the project work to be performed in an economically efficient, cost effective, and safe manner.

V Options Analysis

Alternatives were considered for two sets of investments, the first being #6 Conductor Replacement, the second being Station Transformer Oil Containment. These two investment groups account for 74% of the overall spend. All other investments are not material with respect to cost over the DSP period, and therefore, limited alternatives were considered.

5.1 #6 Conductor Replacement

Alectra Utilities reviewed three options to address the failure and safety issues with #6 conductor:

1. Invest in all areas,
2. Invest in High Priority Areas, or
3. Do Nothing.

Option 1: All Areas

Under this option all 25 areas containing # 6 conductor (5 high priority, 10 medium priority, and 10 low priority) would be replaced under the DSP period. Under this option rate impacts to customers would be the highest, and the risk of failing cable would be the lowest. Based on customer feedback during phase one, where customers indicated price was the greater concern, Alectra has not adopted this approach since it eliminates all risk at the highest cost.

Option 2: High Priority Areas

Under this option only the five high priority areas will be replaced within the DSP period. This removes the greatest amount of risk to customers and Alectra Utilities, but also manages rate impact. Alectra Utilities would continue to monitor the areas of medium and low priority, and alter plans accordingly should condition change. While this plan still leaves customers and Alectra Utilities at risk, it will have a lower rate impact in comparison to option 1. Alectra Utilities selected this approach.

Option 3: Do Nothing

Under this option, rate impact would be the lowest amongst the three options. However, there would be no risk mitigation. Alectra Utilities believes this approach would constitute imprudent management of the distribution system, and not in line with customer’s expectations of good utility practice. This option would also not aligned with Horizon Utilities' agreement with the ESA to proactively remove #6 conductor and could potentially constitute non-compliance on a safety issue. Accordingly, Alectra Utilities rejected this option.

5.2 Station Transformer Oil Containment

Alectra Utilities considered three options to address the risks associated with stations transformer oil leaks:

1. Install oil containment on all transformers within DSP period,
2. Install oil containment on all transformers over 10 years, or
3. Do nothing.

Option 1: Install oil containment on all station transformers within DSP period

Under this option associated environmental risks can be mitigated as Oil containment systems will prevent any possible oil spill or leak from making its way into the surrounding environment. Costs are higher under this option, but it would provide the greatest benefit. Due to the significant potential environmental and customer impact of oil spills and leaks, Alectra Utilities believes that the benefit of installing oil containment as quickly as possible outweighs the cost. Alectra Utilities selected this option.

Option 2: Install *oil containment on all station transformers over 10 years*

Under this option environmental risks would ultimately be mitigated and costs in the DSP period would be lower then Option 1. However, due to the significant concern to the environment, and the additionally unnecessary costs for cleanup Alectra Utilities believes risk mitigation sooner is the correct option. Hence, while ultimately achieving the same benefit Option 1 was selected as the risk impact of oil spills and leaks is too great to defer over 10 years.

Option 3: Do Nothing

Under this option Alectra Utilities would continue without oil containment. With no oil containment system a catastrophic failure of the transformer may result in a massive oil leak, resulting in environmental damages as well as safety risks to the adjacent properties. Many of these units also contain PCBs which would increase the environmental impact. Costs for such events could be significant, and would be magnified based on the location of specific transformers and their proximity to waterways. Furthermore, if the station is ultimately deemed unnecessary (under future renewal investments) cost to remediate before sale would be significant as oil will have leaked deeper into the soil over time. Alectra Utilities rejected this option as it poses an unacceptable risk to Alectra Utilities and to customers.

VI Investment Projects

There are no material projects and initiatives for Safety and Security from 2020 to 2024.

Appendix A16 - Distributed Energy Resources (“DER”) Integration

Overview

The Distributed Energy Resource (“DER”) Integration investments will build Alectra Utilities’ capability to monitor; control; and optimize the integration of DERs (e.g., solar generation, battery storage, smart thermostats, electric vehicles (“EVs”)) into the distribution system, and to provide real-time transparent, tracking and management of DER participation in energy services. The investments that are planned for the 2020-2024 period will enable Alectra Utilities to effectively serve the increasing amount of customers that already are and will continue to adopt DERs in its service area. Ontario already has at least 4,100 MW of DERs that have been contracted or installed in the last 10 years[141]. This DER capacity growth closely rivals the 5,600 MW net growth in transmission-connected generation added during that same time period.

The DER Integration investments consist of two projects:

(1) DER Control Platform: This project will integrate DERs with Alectra Utilities’ traditional distribution operation systems and enable the utility to optimize the operation of DERs.

(2) Smart DER Platform: This project will involve the development of a platform that utilizes blockchain technology to enable real-time processes for procurement, smart contracting, automated verification and settlement for customers participating in grid services with their DERs.

The DER Control Platform project provides an integration backbone for DERs, including hardware and software services, to be controlled and managed through Alectra Utilities’ core operational and control platforms. The Smart DER Platform project enhances the value of DER integration by providing customers with more choice over their energy and costs, thereby providing the utility with an effective means of identifying the introduction of DERs into the distribution system which is a pivotal utility problem associated with the proliferation of DERs.

While the initial load to be controlled will be modest – approximately 100 kW – the DER Control Platform project will enable Alectra Utilities to assess the integration and operation of the platform

[141] IESO. (2018). 2018 Electricity Data. Retrieved from http://www.ieso.ca/en/Corporate-IESO/Media/Year-End-Data.

before it is used at a larger scale to provide benefits to the distribution system as a whole. As more DERs are connected to Alectra Utilities' system, the DER Control Platform will enable Alectra Utilities to optimize DER operations to prevent power quality issues and reduce peak demand in real time. It will also provide valuable data for improving Alectra Utilities' forecast of DERs uptake and operation based on customer adoption that can be used for utility planning purposes.

The Smart DER platform will enable customers and the utility to transparently record the flow of electricity to and from DERs, enabling the efficient procurement of energy services, such as demand response, solar generation and frequency regulation. The Smart DER Platform will provide a robust settlement mechanism backed by timely and efficient financial transactions to enable overall trust and customer value delivery, leading to increased customer satisfaction.

The planned projects will create multiple benefits for Alectra Utilities' distribution system and its customers, including:

1. Improved distribution system planning to enable system right-sizing and optimal expansion;
2. Improved safety and system performance through effective control and monitoring of DERs; and
3. Enhanced understanding of customer needs and behaviour.

Improved Distribution System Planning: Alectra Utilities expects that these projects will provide valuable data to improve system planning practices. The planned projects will help the utility incorporate the benefits of DERs for the benefit of all customers by reducing peak demand, and deferring or avoiding the need for traditional distribution investment. Alectra Utilities may be able to lower the energy costs for the entire customer base by proactively managing DER in such a way that incremental infrastructure cost upgrades to safeguard the grid from DER adoption or power quality issues are mitigated. This will include any upgrades, maintenance or reactive outage related costs incurred due to overloading of the distribution network. The planned projects will also enable Alectra Utilities to encourage adoption in areas where the value of managing DERs is highest, for example where feeder capacity is limited or where transformers are overloaded.

Improved Safety and System Performance: The projects planned for the DSP period will advance Alectra Utilities' ability to control and monitor DERs connected to the distribution network, ensuring DERs are isolated from the grid to protect the employees working on the network during outages. The planned projects will provide valuable learnings on how to mitigate the future risks introduced by high penetration of DERs in a typical distribution network, including power quality issues, safety concerns and adverse impacts of intermittent and uncontrolled DERs. In the absence of these learnings, Alectra Utilities will be faced with reactionary infrastructure upgrades required to safe guard power quality and reliability standards, since it will not have the ability to perform real-time management of DERs to balance the system or provide peak shaving opportunities.

Enhanced Understanding of Customer Needs and Behaviour: The projects will provide Alectra Utilities' further understanding of customer needs and behaviour associated with DERs. Understanding customer DER needs and behaviours is important because it is ultimately the customers that will adopt these DER technologies. Alectra Utilities needs to integrate, optimize, control and manage DERs in ways that maximize the benefits of DERs for the grid as well as for the customers. For example, the DER Control and Smart DER platforms will provide enhanced information and analytics on, but is not limited to, customers' preferred DER ownership structures and control features, and DER incentive structures that promote the effective use of DERs on the distribution system. Without this information obtained from the two platform investments, Alectra Utilities would be limited with establishing the right balance of ownership and control customers want over DERs, which impacts Alectra Utilities' ability to monitor, optimize and control DERs for the benefit of the grid. In addition, Alectra Utilities would be limited in understanding how to incentivize DER uptake and participation in DER management programs in areas where capacity constraints or issues in power quality or reliability may exist. As a result, customers may not be inclined to allow Alectra Utilities to control the operation of their DERs or customers may not want to participate in DER management programs if the incentives to participate in such programs aren't adequate.

Table A16 - 1: Investment Subgroup Summary ($MM), Drivers and Outcome Summary

	Historical Spending				Bridge	Forecast Spending				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$0.0	$0.0	$0.0	$0.0	$0.90	$0.66	$0.67	$0.90	$0.91	$0.92
Primary Investment Driver:	Capacity Constraints									
Secondary Driver:	Customer Access and Choice									
Investment Outcomes:	Efficiency, Coordination/Interoperability									

Investment Description

The DER Integration investments planned over the 2020-2024 DSP period are driven by expected increasing adoption of DER in Alectra Utilities' service territory and the significant challenges and opportunities that such a trend presents for the utility's distribution system and for its customers. At least 4,100 MW of DERs have already been contracted or installed in Ontario in the last 10 years[142]. This does not include an unrecorded amount of load control, behind-the-meter energy storage and demand response capacity that can also be regarded as DERs. This DER capacity growth closely rivals the 5,600 MW net growth in transmission-connected generation added during that same time period. Some estimates indicate that the most of the newly installed generation (transmission and distribution connected generation) could be on the distribution side as soon as 2023 in certain parts of the world, such as the U.S.[143] For example, in the United States, the most recent edition of the U.S. Energy Information Administration's (EIA) Long-Term Energy Outlook projects DERs to be the fastest growing segment of America's electricity industry generating capacity for the next 30 years[144].

In its own service territory, Alectra Utilities has connected over 5,409 renewable projects including FIT, microFIT, and commercial and residential net metering installations comprising over 147.9 MW of potential generation: 564 FIT contracts with 108.4 MW of installed capacity and 4,845 microFit contracts with 39.5 MW of installed capacity. Forecasts of these DER technologies indicate that North America is expected to install 260.1 GW of solar photovoltaic (PV) between 2018 and 2027 at a compound annual growth rate (CAGR) of 14.0%[145] . In terms of EVs, there were 83,000 EVs on the road in Canada as of Q3 2018[146] and one third of Ontario EVs,

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[142] IESO. (2018). 2018 Electricity Data. Retrieved from http://www.ieso.ca/en/Corporate-IESO/Media/Year-End-Data.

[143] John, J. (2018). Distributed Energy Poised for 'Explosive Growth' on the US Grid. *Green Tech Media*. Retrieved from https://www.greentechmedia.com/articles/read/distributed-energy-poised-for-explosive-growth-on-the-us-grid#gs.kd4L=NM

[144] United States Energy Information Administration, "Annual Energy Outlook 2019", January 24, 2019 Table: Electricity Generating Capacity, Case: Reference case

[145] Navigant. 2018. Market Data: Solar PV Global Forecasts. Retrieved from https://www.navigantresearch.com/reports/market-data-solar-pv-global-forecasts

[146] Fleet Karma. (2018). Electric Vehicle Sales Update Q3 2018, Canada. Retrieved from https://www.fleetcarma.com/electric-vehicles-sales-update-q3-2018-canada/

approximately 10,000 vehicles, are in Alectra's service territory[147]. With Ontario EV sales increasing 60% year-over-year for the past five years[148], Alectra could expect a higher adoption of EVs in its service territory in the next few years. These increasing trends across many DER technology sectors further demonstrate the need for Alectra Utilities to adopt platforms that will enable DERs to contribute to grid services and energy markets and provide value to customers.

The increasing adoption rates of DERs are driven by the following global mega trends:

1. Rapid technological innovation driving down the costs of various energy technologies
2. Changing customer preferences - desiring more energy options, control, engagement and customization
3. Increasing threats of climate change pushing the de-carbonization of energy systems
4. Intensifying urbanization

Energy Technology Cost Curves

In 1970, the average cost of solar PV was $100/Watt (W) and every year since the cost of solar has reduced by 11.5%[149]. Now in certain parts of the world, solar cost is $0.30/W[150]. In Ontario, the cost of solar is $3.07/Watt as of 2019[151] and is expected to continue to follow the declining cost curve experienced in other markets. Similarly, lithium ion battery costs have reduced by 20% per year between 2010-2016[152]. Electric vehicles ("EVs") have been and will continue to benefit from declining lithium ion battery costs as Bloomberg New Energy Finance predicts that EVs will become cost competitive against comparable combustion engines as early as 2024[153]. Finally, Ernst and Young estimates that the north eastern regions of North America are 13 years away

[147] Ontario Ministry of Transportation
[148] Fleet Karma. (2018). Electric Vehicle Sales Update Q3 2018, Canada. Retrieved from https://www.fleetcarma.com/electric-vehicles-sales-update-q3-2018-canada/
[149] Seba, T. (2017) Clean Disruption of Energy and Transportation, Clean Energy Action Conference, June 8 2017
[150] Seba, T. (2017) Clean Disruption of Energy and Transportation, Clean Energy Action Conference, June 8 2017
[151] Energy Hub. (2019). Cost of Solar Power in Canada 2019. Retrieved from https://energyhub.org/cost-solar-power-canada/
[152] Seba, T. (2017) Clean Disruption of Energy and Transportation, Clean Energy Action Conference, June 8 2017
[153] Bloomberg New Energy Finance. (2018). Electric Vehicle Outlook 2018. Retrieved from https://bnef.turtl.co/story/evo2018?teaser=true.

from reaching cost parity between off-grid customer solar-storage and customers staying on the grid and paying their utility's electricity bills[154]. Within another 8 years it is estimated that the north eastern region of North America will have a completely decentralized electricity system as the cost of transporting electricity will exceed the cost of generating and storing it locally[155] .

Intensifying Urbanization

The United Nations estimates that 70% of the world population will live in urban areas by 2050[156]. Canada already surpasses this threshold as 81% of the population lives in urban areas[157]. Alectra Utilities serves some of the fastest growing neighbourhoods in Canada: Markham's population is expected to increase by 52% by 2041, Brampton's by 50% and Guelph's by 45%[158]. Given this rapid intensification and urbanization in Alectra Utilities' service territory, Alectra Utilities can expect to experience high levels of load growth in these areas. DERs can provide an alternative to infrastructure investments or help increase power quality as the populations in the communities it serves increase.

The need to proactively manage DERs within Alectra Utilities' distribution system

As customer preferences with respect to energy evolve in favour of more choice and greater control and customization, traditional distribution system planning and operation needs to change as well. While rapid technological innovation is driving down the costs of energy technologies, an increasing level of DER penetration will impact how the traditional distribution system will be operated. These changes must be understood and represented in the planning and operation of the distribution system through higher visibility of assets, effective communication, and coordinated activities. DERs pose potential challenges in terms of: increased intermittent generation; unexpected fluctuations in supply and demand; and the potential for stranded assets. The following is an overview of the key areas of focus to understand the nature of DERs and their impact on the distribution system:

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[154] EY. Alectra September 2018. Presentation.
[155] EY. Alectra September 2018. Presentation.
[156] United Nations. (2018). 68% of the world population projected to live in urban areas by 2050, says UN. Retrieved from https://www.un.org/development/desa/en/news/population/2018-revision-of-world-urbanization-prospects.html.
[157] Statistics Canada. (2018). Canada goes urban. Retrieved from https://www150.statcan.gc.ca/n1/pub/11-630-x/11-630-x2015004-eng.htm.
[158] Appendix A13 - Stations Capacity, Table 3

Ramping and Variability: Certain types of DERs create significant changes in power requirements, such as morning and evening solar ramp ups/down that are different than those historically experienced by the distribution system. Readiness of the distribution system for planning, installation, and operation of DER resources is an ongoing need as the generation resource mix evolves on both transmission and distribution systems.

Reactive Power: Modern technologies, including inverters for new rooftop solar PV installations, have the capability to support voltage and ride-through voltage excursions. Use of these capabilities will be increasingly important to support the reliability of both the transmission and distribution systems.

Frequency Ride-Through: As DERs are added to the system, frequency and voltage ride-through capabilities become more important and must be considered both locally and for bulk electric system to improve the reliability.

System Protection: High levels of DER with inverters can also result in a reduction of short circuit current, which can make it more difficult for protection devices to detect and clear system faults. Hence, the implications of DERs as part of system protection must be taken into consideration while planning the distribution systems.

Visibility and Control: Many DERs are generally not visible to the utility. The lack of visibility and control is not only a challenge for operations, but must also be accounted for in the planning of the distribution system. At higher penetration levels, the need for DER visibility and control becomes increasingly critical.

Interconnection Requirements: Interconnection requirements are evolving with increasing DER penetration. Consequently, a number of DER classes with very different dynamic behaviours will emerge in the distribution system. It will be important to understand this information, at least in aggregate, so that the dynamic characteristics can be modeled correctly for system planning.

Potential Risks to Reliability: With increased DER adoption, the effect of these resources presents certain reliability challenges that require careful understanding and measured actions. This leads to a need for further study to better understand the impacts, and how those effects can be included in planning and operation of the distribution system.

Data on installed and projected DER units is needed for reliability modeling purposes. Important data for modeling includes information on the location, type, size, configuration, interconnection characteristics, disturbance response characteristics, and schedule of operation of the equipment. DER generation profiles would also improve the accuracy of modeling results rather than forcing models to assume worst-case scenarios.

Utilities require sufficient levels of reliability measures, from on-line resources, for reliable operation of the distribution system. It is not necessary that all resources provide services at all times, but if conventional resources are off-line or replaced by DERs, it may be increasingly important to use DERs for active power control and essential reliability services.

<u>Voltage Fluctuation:</u> Frequent power variations due to intermittent and un-controllable nature of certain DERs cause voltage fluctuations that were not anticipated in the original design of feeders, especially radial distribution feeders. These fluctuations will have an impact on the frequency of operation of feeder voltage-regulating equipment. It is important to assess, monitor and manage the impact of varying DER output on distribution system operation performance.

The many unexplored features of DERs, such as but not limited to integration challenges, power quality issues, and safety considerations, require further investigation to minimize the risk and optimize the value to the distribution system.

As DER adoption continues to rise, Alectra Utilities expects that distributors will need to revise its approach to distribution system planning to maximize the benefits of DERs to the system, while maintaining reliability and reasonable costs for customers. The planned DER Integration investments are required for Alectra Utilities' to build capabilities and learnings to be prepared to plan and build a system that can safely integrate and optimize value from DERs.

Alectra Utilities will consider not only how DERs can be more fully integrated into the system to take advantage of DER benefits, but also how traditional distribution system planning and investment can account for DERs. Alectra Utilities will identify and communicate the hosting capacity considerations, utility needs and constraints to allow the adoption of DERs, and will increase access to certain types of system information to enable customers and DERs providers to help meet the grid needs. Alectra Utilities will have projections of DERs penetration in various parts of the system to ensure a thorough understanding of risks and opportunities, and will standardize interconnection requirements to maintain and enhance the reliability and flexibility of the grid with increased DER integration. Alectra Utilities needs to learn how to plan for, monitor, control and optimize the safe and reliable integration of DERs onto such a distribution system, as well as develop business processes on how to provide real-time transparency, tracking and management of DER participation in energy services. These are the drivers and objectives of the two DER Integration projects planned for the 2020-2024 period, as described in the following sections.

Project 1: DER Control Platform

The objective of the DER Control Platform project is to integrate DERs with Alectra Utilities' traditional distribution operation technology systems. It will enable Alectra Utilities to: build capabilities that could predict the grid operational impacts of DERs; help mitigate power quality issues associated with DERs; and reduce peak demand. These capabilities will be built as part of the overall DER Control Platform, also known as Distributed Energy Resource Management System ("DERMS"), further enabling a Virtual Power Plant ("VPP"), with integrated controls and real time signals in order to operationalize DERs as an aggregated source of capacity and storage.

The focus of Alectra Utilities' DER Control Platform project is to aggregate, integrate, control and optimize concentrated and dispersed DER, as a source of virtually aggregated deployment, in order to reduce system capacity demand necessary for system optimization and load balancing.

The expected benefits of the DER Control Platform project include:

- Enabling integration of DERMS with Alectra Utilities system control and operational systems, including Supervisory Control And Data Acquisition ("SCADA"), Geographical Information System ("GIS"), Outage Management System (OMS) and Network Simulation Software.
- Enabling system planning and business process development within Alectra Utilities to utilize DER deployment as a feasible non-wires solution to defer distribution and transmission infrastructure expansion;
- Establishing public and employee safety practices, protection settings and standards to facilitate safe and reliable operations of distribution system with high DER penetration;
- Understanding customers' preferred DER ownership structures and control features so that Alectra Utilities can determine the right balance of ownership and control that

customers want over DERs, which ultimately informs how Alectra monitors, optimizes and controls the DERs for the benefit of the grid and customers;

- Implementing a secured infrastructure through necessary cyber security standards to facilitate a secure and reliable real-time communications necessary for monitoring and controlling DERs; and
- Monitoring, controlling, coordination, and management of DERs connected to the utility using a real-time communication infrastructure.

Through Alectra Utilities' DER Control Platform, the utility aims to provide a flexible and scalable solution to effectively engage with its customers with DERs, support optimization of their DER utilization and provide automated business processes around DER management. The platform will be designed to address challenges in utility planning, communications and operational processes for Alectra Utilities to ensure successful integration of DERs. For instance, by utilizing field data from GIS, SCADA and DERs, the platform will be able to support the development of efficient models to address the challenges in utility network planning, as well as ancillary decision-making at operational and planning levels. The DER Control Platform will help Alectra Utilities to ensure that growing DER challenges are met through supporting efficient network planning and impact analysis and provide visibility of the entire network state in real-time. It will provide the ability to define, aggregate, forecast, settle and control DER within Alectra Utilities' service territory. For instance, using DER generation forecast analysis and DER optimization techniques, Alectra Utilities will be able to manage grid resources more effectively.

By undertaking this project now, Alectra Utilities is preparing the distribution system to efficiently, safely and reliably respond to the expected uptake of DERs and optimize the benefits of DERs to customers and the grid. Without Alectra Utilities' Control Platform, Alectra Utilities will not be able to realize the full potential benefit of DER integration.

Project 2: Smart DER Platform

The objective of the Smart DER Platform is to develop the real-time administration platform and processes needed to manage: solar PV; battery storage; EVs; and other DERs to both reduce their adverse impact on the grid, and provide capacity and power quality services. The platform will also help Alectra Utilities to strengthen control and visibility over DER owners and provide benefits to the entire customer base over the long-term

Power.House was Canada's first virtual power plant that uses an aggregate fleet of 20 residential solar PV and battery storage units at customer homes that can be autonomously controlled, aggregated and monitored through software to simulate a single, large and sustainable power generating facility. Participating customers benefit from cost savings and outage protection, while Alectra Utilities can use these resources to provide benefits to the grid, such as demand response, operating reserve, and regulation service The Power.House pilot project allowed Alectra Utilities to test the ability of DER to safely and reliably provide the above-mentioned grid services in various scenarios.

Alectra Utilities preformed a follow-up study to determine a technical and economically feasibility uptake of 30,000 Power.House units in the York region, by 2031, including a 2 year deferral of distribution infrastructure[159]. Further to the Power.House feasibility study, Alectra Utilities conducted a separate investigation to evaluate the use of DER to defer capital investment for distribution reinforcement in Markham-Richmond Hill area. The study determined that in order to defer capital investment for a 2-year period under existing levels of distribution system efficiency (0.9 power factor measured at the substation), a fleet of 21,711 residential storage devices providing active power to the grid were required. By using smart inverters to regulate the reactive power and improve the power factor from 0.9 to 0.95, we can achieve the same deferral benefit by just using 2,647 residential storage devices. The study confirmed that DER solutions in the distribution system are a feasible solution to be piloted as an alternative to the traditional wires expansion typically considered to meet growth and expansion needs.

Alectra Utilities aims to leverage these existing Power.House customers to participate in an energy marketplace powered by a blockchain-based software platform. Blockchain technology essentially provides a distributed ledger that can record transactions between two parties efficiently, and in a verifiable, permanent and secure way. Through the Smart DER Platform, Alectra Utilities will issue requests for the Power.House customer systems to provide distribution energy services where each aspect of customer participation will be transacted through and recorded transparently in real-time by the platform. The Smart DER Platform will provide end-to-end visibility on customer usage and DER participation patterns, and such information can only

[159] Alectra. Power.House Feasibility Study.

be accessed by parties who have been granted permission through the platform. By analyzing these patterns, Alectra Utilities can prove to be a highly effective intermediary between understanding customer usage and changing customer behavior, consequently providing tangible incentives that promote the beneficial use of DERs to customers and the distribution grid.

Therefore, the project is a pre-requisite for the widespread adoption and utilization of DERs, and includes the following benefits:

- Developing efficient procurement processes around customers and local distribution companies;
- Enabling real-time smart contracting capabilities binding the provider and the customer through contractual obligations;
- Providing real-time and efficient financial settlement processes to improve customer trust and engagement leading to higher customer value;
- Securing compliance obligations through a set of highly measurable and transparent verification processes around energy transactions/incentivization between customers and utilities;
- Emerging sector interest in developing regional or distribution-level markets to enable DERs to provide local system needs;
- Understanding the incentive structures that effectively promote customers to uptake DERs and participate in DER management programs in ways that benefit both the grid and customers;
- Enabling Alectra Utilities to defer or avoid investment in distribution infrastructure by leveraging the value of widespread adoption of DERs; and
- Minimizing the negative impact of DERs on the operation of the distribution grid

2.1 Summary of Investment Outcomes and Benefits

Table A16 - 2: Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Efficiency	The integration of DERs with Alectra Utilities' traditional distribution operation technology systems will enable Alectra Utilities to optimize the operation of DERs to prevent power quality issues and reduce peak demand. In addition, these projects will provide valuable data to improve Alectra Utilities' system planning practices by incorporating the benefits of DER uptake and operation to reduce peak demand and defer traditional distribution investment. Currently, these values are not incorporated in Alectra Utilities' system planning practices. As DER penetration increases, ignoring these resources will lead to economic inefficiencies, as Alectra Utilities would require investment for additional infrastructure to manage the impact of the DERs on the distribution system. The projects remove key barriers to the utilization of DERs and will promote participation in distribution and wholesale electricity energy services. They will enable and enhance the utility's opportunity to ensure better visibility of the location, size and application of the integrated DERs that are being introduced in Alectra Utilities' system, while providing customers with tangible benefits from integration. By bringing the procurement, contracting, settlement, and verification functions required to administer a market into a Smart DER Platform, we expect significant process and cost efficiencies from removing integration or coordination of separate platforms. It will also facilitate broader adoption of DERs by customers by providing an accessible way for them to participate and obtain value.
Customer Value	By optimizing DER operations, Alectra Utilities can maximize the benefit of DER connected to the network to mitigate power quality and capacity limitations constraints. Therefore, the planned investments enable greater energy choices for Alectra Utilities customers who wish to consume and generate their own electricity while remaining connected to the network. The projects will also allow customers with DERs to better utilize their DER capability while also providing a benefit to the grid. In return, these customers

Outcome	Investment Benefits and Objectives
	will receive payment for the services they provide – generating value for these customers. Customers benefit by saving money on their electricity bill and making money through selling self-generated electricity back to the grid. In terms of customers without DERs, Alectra Utilities may be able to lower the energy costs for the entire customer base by proactively managing DERs in a way that incremental infrastructure cost upgrades to safeguard the grid from DER adoption or power quality issues are mitigated. This will include any upgrades, maintenance or reactive outage related costs incurred due to overloading of the distribution network.
Reliability	By developing the contracting, verification, and settlement infrastructure that allow the coordination of DERs, Alectra Utilities can utilize these DERs to prevent distribution assets from being over loaded. They can be a cost-efficient alternative to traditional grid infrastructure investments and be used so that Alectra Utilities can maintain a reliable electricity supply for all customers.
Safety	The projects will advance Alectra Utilities' ability to control and monitor DERs connected to the distribution network – ensuring DERs are able to be isolated from the grid in order to protect the employees working on the network during outages.
Cyber-security and Privacy	Cyber security and data privacy are key considerations for the projects, given the integration of assets located in customer's homes with Alectra Utilities' system control and operational systems, such as, but is not limited to, SCADA, GIS and OMS. Through these projects, Alectra Utilities' aims to participate in the development of industry leading practices adopting cyber-security technologies, architecture and standards for a distributed electricity network. The projects will be backed by a robust blockchain infrastructure with cyber-security and data privacy at its core. Blockchain technology essentially provides a distributed ledger that can record transactions between two parties efficiently, and in a verifiable, permanent and secure way. Through the Smart DER Platform, Alectra Utilities will issue requests for the Power.House customer systems to provide distribution energy services where each aspect

Outcome	Investment Benefits and Objectives
	of customer participation will be transacted and recorded transparently in real-time by the platform. The Smart DER Platform will provide end-to-end visibility on customer usage and DER participation patterns, and such information can only be accessed by parties who have been granted permission through the platform.
Coordination / interoperability	The projects will provide the procurement, contracting, verification, settlement, control and monitoring processes required for coordination and interoperability of DERs with the existing electricity distribution network. Without this coordination of DERs, Alectra Utilities will be unable to cost-effectively procure, coordinate and optimize the application of DERs and will either have to enhance its network with traditional infrastructure and/or limit connections of DERs to the network. Meanwhile, if the DERs are managed as an aggregated fleet, local benefits such as reduced transformer or feeder loading could be achieved by scheduling for DERs to shave load or self-generate during peak periods.
Environment	One of the use-cases demonstrated by the Smart DER Platform is a greenhouse gas (“GHG”) avoidance market. The platform will receive near-real time data on the GHG intensity of the grid from the IESO, triggering a response from participants to reduce their electricity consumption or discharge their battery above a pre-set GHG threshold. This will demonstrate the ability for the platform and participants to achieve targeted, verifiable reductions in GHGs. Furthermore, DERs tend to be zero-emissions technologies, therefore, increasing the penetration of these technologies reduces output from GHG emitting centralized electricity generators.
Other Benefits	Evaluate DERs as system planning alternatives. Understanding of DER capabilities will enable Alectra Utilities to utilize DER deployment as feasible non-wires solution to defer distribution and transmission infrastructure expansion.

III Investment Drivers and Need

The DER Integration projects are driven by the following investment needs:

- Understand, mitigate and reduce the risks DERs pose regarding capacity constraints, power quality, and reliability on the distribution grid and ready Alectra Utilities' distribution system to accept and support DERs, including electric vehicles, solar PV systems, and battery storage
- Improve efficiencies around integrating, controlling, optimizing, tracking, and settling transactions with DERs on Alectra's distribution grid
- Provide customers with the alternative choices to the traditional electricity supply model, including the DER technologies and ownership structure, and participation in grid benefiting services
- Reduce energy affordability issues that arise when DERs are unmanaged

By undertaking these projects now, Alectra Utilities is preparing the distribution system to safely and reliably respond to the expected uptake of DERs with a coordinated architecture that balances the benefits of DERs to their owners, with the costs they potentially pose on all of Alectra Utilities' customer-base.

Without this preparation, Alectra Utilities introduces the risk of:

- supressing customer choice in the short term due to constraints in the distribution system to support DERs;
- creating power quality and reliability of supply issues as a result of intermittent, uncontrolled generation from DERs, and the increasing frequency and duration of interruptions to grid supply from adverse weather conditions; and
- reactionary and expensive upgrades to distribution infrastructure in response to these risks.

3.1 Purpose

Table A16 - 3: Investment Drivers

Investment Driver	Reasoning and Investment Benefits
Capacity constraints, power quality, and reliability	Implementation of the projects provide Alectra Utilities a prudent and paced manner to evaluate and understand all implementation and operational issues as well as benefits of DERs. The uptake of DERs in Alectra Utilities' service areas pose both a risk and an opportunity for the distribution system: • DERs which include solar PV panel and EVs have the potential to impact peak demand and create power quality issues in the network – if operating in an uncoordinated manner without visibility by the Alectra Utilities. • DERs such as battery storage units or smart inverters can help to provide back-up supply during grid outages, reduce peak demand, and alleviate power quality problems The DER Integration projects seek to coordinate and incentivize DER uptake and operation, and avoid these negative impacts. Finally, the projects will implement the operational monitoring and control technologies required for real-time control over DERs in order for Alectra Utilities to maintain supply capacity within existing infrastructure, and maintain voltages within standard requirements.
Efficiency	For Alectra Utilities to manage DER integration, it needs to undertake the following functions: - Procurement: transparency between customers and the utility to ensure efficient procurement of services. • Contracting: ability to secure services with performance requirements and penalties bound by contractual obligations. • Compliance: measurement and verification of participant performance to ensure they meet contractual obligations.

Investment Driver	Reasoning and Investment Benefits
	• Settlement: timely and efficient financial settlement according to terms agreed upon through contracting. Using blockchain technology, the transaction management aspect becomes much more simplified, transparent and trustworthy with respect to a traditional legacy implementation, such as a centralized database [160]. Alectra Utilities expects reduced management and auditing overhead from each of these processes due to the inherently secure architecture of a blockchain based platform. For example, the ability to code digital contract terms and verify and settle transactions instantaneously will reduce the overhead associated with contract management.
Customer access and choice	Customers increasingly expect Alectra Utilities to provide choice in how electricity is consumed and produced. DERs have the potential to be an economic and environmentally friendly alternative to the traditional wires solution for our customers. Alectra Utilities endeavors to develop cost-effective access to the distribution system without adversely impacting the safe and reliable operation of the system. The DER Integration projects will develop the operational systems and business processes to maximize the safe, reliable, and fair connection of DERs with Alectra Utilities' network. The project will also enable a commercial framework that allows DER owners to allow their assets to contribute to grid management, and help optimize DER operations to allow for greater uptake within the traditional distribution system.

[160] IBM, https://www.ibm.com/blogs/blockchain/2019/01/whats-the-difference-between-a-blockchain-and-a-database/

Investment Driver	Reasoning and Investment Benefits
Customer affordability	Affordability of electricity is a priority for Alectra Utilities' customers. As the price of DERs has fallen, they have the potential to deliver significant electricity bill savings to customers. However, if not managed appropriately, there is a risk of increasing electricity costs for other customers. For example, unmanaged solar PV generation will require new network infrastructure to manage power quality (e.g. over-voltage) and reverse power flow – paid for in-part by non-PV owners. Alectra Utilities' DERMS and Smart DER Platforms will help proactively mitigate those risks and maintain customer affordability.

IV Investment Timing and Pacing

4.1 Summary of Expenditures

Table A16 - 4: Historical and Proposed Investment Spending

	Historical Spending				Bridge	Forecast Spending				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$0.0	$0.0	$0.0	$0.0	$0.90	$0.66	$0.67	$0.90	$0.91	$0.92

4.2 Historical Expenditures (2014-2019)

Alectra Utilities has successfully completed pilots of emerging technologies and shared learning with other distributors as well as industry stakeholders to facilitate the development and solutions for customers interested in alternative electrical supply choices. It is important to note the scope and scale of historical projects differs from the proposed DER Integration projects, hence historical expenditures for such projects are not included in Table A16 - 4 above. Examples of successful projects completed by Alectra Utilities or legacy utilities that formed Alectra Utilities include:

- Power.House Pilot Project (as described in Section 2 above)
- Alectra Utilities' Cityview Microgrid is designed to seamlessly connect or disconnect from the distribution system. Alectra Utilities implemented its Microgrid demonstration project

in two phases. In phase one, Alectra Utilities generated electricity from a solar array, a wind turbine, and a battery storage system in order to provide electricity to building loads such as lighting, air conditioning and refrigeration. Electricity generated from this combination of clean and renewable sources was used to power an electric vehicle charging stations and to maintain a steady charge in the Microgrid's storage batteries. In the second phase of the pilot, Alectra Utilities developed an integrated solution to control and optimize the connected assets, including the electric vehicle charging station, vehicle-to-grid charging station, the solar battery storage system and load bank to introduce peak demand management, and to participate in simulated demand response events.

4.3 Future Expenditures (2020-2024)

Future expenditures from 2020 to 2024 for the two DER Integration projects will total $4MM. The proposed projects are a limited step toward evaluating how different platforms, such as the DER Control Platform and the Smart DER Platform, can prepare Alectra Utilities to reduce the previously mentioned risks and maximize the benefits of DERs integrated with Alectra Utilities Distribution system. Such integration projects will provide Alectra Utilities with a direct real-time communication link with the status and condition of DERs on the distribution network, and the means to optimize and coordinate DER outputs for the benefit of the distribution system and customers connected to it.

4.4 Investment Pacing and Prioritization

These two DER Integration projects will be conducted simultaneously because the projects address two very different and specific needs:

1. DER Control Platform: this project will integrate DERs with Alectra Utilities' traditional distribution operation systems and enable the utility to optimize the operation of DERs to benefit both the grid and customers.
2. Smart DER Platform: This project will develop a platform that uses blockchain technology to enable real-time processes around procurement, smart contracting, automated verification and settlement for customers participating in grid services with their DERs.

As the learnings from these projects are equally important for Alectra Utilities to prepare the distribution system to safely and reliably respond to the expected uptake of DERs, Alectra Utilities will pursue these projects simultaneously during the 2020-2024 period.

Between the two projects, the different activities will be prioritized based on their interdependencies. For example, the procurement process within the Smart DER Platform will have a direct dependency on DER Integration as part of the DER Control Platform, and will be prioritized accordingly.

These projects will be prioritized in areas within Alectra's service territory where the adoption and the management and control of DERs with DER Integration Platforms, such as the DER Control Platform and Smart DER Platform, can offset or reduce grid issues. Areas typically categorized with high growth, low reliability or capacity will be targeted as beneficial sites for DER adoption and subsequent testing of the DER Integration Platforms that mitigate the risks and maximize the benefits of DERs.

4.5 Execution Approach

Alectra Utilities will utilize internal staff and external vendors to complete the design and execution of the two projects. Specifically, the execution phase will follow Alectra Utilities' project management practices, which provides guidelines, procedures, work instructions, and industry best practices that allow the project work to be performed in an economically efficient, cost-effective, and safe manner.

Constraints

Due to the emerging nature of certain of the technologies tested at Alectra Utilities, the timing of projects can be constrained by the development efforts and capability of technology vendors. Alectra Utilities mitigates this risk by undertaking thorough and on-going evaluation of potential vendors, and gaining experience with vendors in smaller-scale projects.

V Options Analysis

Alectra Utilities considered several alternatives in developing DER Integration projects:

- Option 1 Be Reactive with Traditional Distribution Infrastructure Investments: Reactively respond to DER uptake and organic load growth by investing in traditional 'poles and wires' infrastructure as capacity, power quality, and reliability issues become apparent. Additionally, Alectra Utilities won't have the capability to monitor and control DERs without a DER Management and Control platform. Option 2 – Being Proactive with DER Integration Projects: Integrate DERs located throughout the network into Alectra Utilities' Advanced Distribution Management System (ADMS), allowing these resources to be controlled, monitored, and optimized by Alectra Utilities and, where applicable, providing the capability to defer or avoid traditional distribution infrastructure upgrades.

Efficiency: Option 1 (Traditional Distribution Infrastructure) requires major replacement/enhancements reactively to the network and is therefore an inefficient option in response to the grid benefits posed by DERs. Option 2 (DER Integration Projects) will provide Alectra Utilities the ability to optimize the operation of DERs to prevent power quality issues, reduce peak demand, and defer/avoid traditional distribution enhancements as DER adoption becomes widespread throughout the network.

Customer value: Option 1 represents the *status quo* for customer value. Option 2 maximizes the number of DERs connected to the network before power quality and capacity limitations constrain the connection of new DERs - provides greater energy choices for our customers who wish to consume and generate their own electricity while remaining connected to the network.

Reliability: Option 1 provides poor reliability in the long term, due to a reactive response to peak demand and power quality issues from DER growth. Option 2 will allow Alectra Utilities to proactively address peak demand growth and power quality issues; thus, ensuring the reliable operation of the network.

Safety: Option 1 - Alectra Utilities' assets will not be at long-term risk of being loaded above operating limits, although the option will not provide Alectra Utilities the monitoring or control capability required for safe operation during outages. Option 2 is the safer option, as it allows

Alectra Utilities to coordinate DER operation during outages, and maintain loading on distribution assets within operating limits in the short and long term.

Cyber-security/Privacy: Although Options 1 provides a greater level of cyber security, it refrains from providing any benefits associated with DER adoption. While there are some new risks associated with Option 2 due to the nascent distributed network being developed, it will be a key requirement of the project to develop best-practice security standards and processes to mitigate any risks.

Coordination / Interoperability: Option 1 minimizes the need for DER coordination and interoperability by instead solving any possible capacity, reliability, or power quality problems with additional distribution infrastructure. Accordingly, this option has limited coordination/interoperability outcomes. Option 2 provides the necessary control and monitoring platform for the physical coordination and interoperability of DERs with the existing electricity network.

Environment: Options 1 represents the status quo for environmental outcomes – centralized electricity generation and distribution. Option 2 allows for increased DER uptake, and therefore offsets GHG emissions from centralized generation, and defers/avoids the need for new infrastructure development in the community.

As a result of considering the criterial of efficiency, safety, reliability, cyber security, interoperability and the environment, Option 2 was selected as the basis for the planned investments in the 2020-2024 period.

VI Investment Projects

The investments from 2020 to 2024 that form the DER Integration investments are included in Table A16 - 5.

Table A16 - 5: Material Projects and Initiatives

Project Code	Project Name	CAPEX ($MM)
150747	DER Control Platform	1.6
150693	Smart DER Platform	2.4

Appendix A17 - Facilities Management

I Overview

Alectra Utilities operates three administrative offices (Derry Road, John Street, Cityview Boulevard) as well as seven operational centers (Addiscott Court, Sandalwood Parkway, Mavis Road, Nebo Road, Patterson Road, Vansickle Road, Southgate Drive) to service seventeen communities across Alectra Utilities' 1,800 square kilometer service area. General plant investment is required to ensure office, and operational center facilities appropriately support the efficient operation of the distribution system and ongoing business operations. The facilities (administrative and operations centres) addressed by facilities management investment are grouped into six sub-categories according to the relevant building system: Security/Life Safety, Generators/Elevators, Building Heating, Ventilation and Air Conditioning ("HVAC"), Building Envelope, Building Outdoor Walkways/Driveways and Building Renewals.

Alectra Utilities has planned investments for the 2020-2024 period in each of these facilities management categories as highlighted below:

- **Security/Life Safety:** Capital investments are necessary to protect Alectra Utilities' assets, employees as well as the public through up-to-date security systems and measures. Alectra Utilities plans to renew security cameras and access control equipment that have reached end-of-life and are technically obsolete and no longer supported by the manufacturer. Required capital investments were established from findings and recommendations from assessments conducted by third party service providers of Alectra Utilities' security system and practices. Investment in security/life safety will improve and ensure consistency in security infrastructure and ensure life systems continue to comply with related regulations and bylaws across all of Alectra Utilities' facilities.
- **Elevators and Generators:** Most of the elevator and generator systems in Alectra Utilities' buildings have not undergone modernization or major renewal since their installation between 1950's and 1990's. Several of the systems have reach the end of their Typical Useful Life ("TUL") during the planning period. Along with the required elevator renewals, several lifting devices require the installation of elevator car top railings. During the last year, some elevators have been out of services for long periods due to the availably of requires parts, affecting daily operation such as the Nebo Road Warehouse

freight elevator. Alectra Utilities uses generators to power critical systems in the event of an emergency (e.g., to support the utility's Control Rooms and main server rooms). Certain emergency generators must be renewed during the DSP period. The need to renew these elevator and generator systems were identified during building physical assessments conducted by third party service providers (discussed in Section 3 below).

- **Building HVAC:** Specific HVAC systems within Alectra Utilities' buildings have not undergone modernization or major renewal since their installation. Several HVAC units are anticipated to approach the end of their TUL. As such, Alectra Utilities plans to renewal HVAC systems for specific buildings.
- **Building Envelope:** Alectra Utilities plans to address issues affecting the building envelope. In particular, Alectra Utilities plans to address brick masonry walls, windows and roofs at specific locations. For example, roof replacements at the Nebo Road and Patterson operation centres are required as the roofs have deteriorated, are leaking and have exceeded their useful life. The poor conditions of many of these assets has resulted an increase of repairs and operating expenditures to maintain a reliable and safe work environment for our employees and the public.
- **Building Outdoor Walkways/Driveways:** Alectra Utilities plans to address issues affecting outdoor walkways and driveways. In particular, interlocking walkways, sidewalks and paving of parking lots at various facilities require renewal investment to mitigate the risk of accidents and permit proper water drainage from the rain. Alectra Utilities has determined that the areas in need of renewal have or will exceed their typical useful live during the DSP period. Planned projects were identified as part of building physical assessments and an *Accessibility for Ontarians with Disabilities Act* ("AODA") assessment conducted by third party service providers.
- **Building Renewal:** Over the DSP period, Alectra Utilities plans to undertake renovation projects at some facilities to reclaim office space to bring groups together that could eliminate current space leases, address safety risks, meet current building regulations, improve work environment for Alectra Utilities employees, remove any hazard materials, reduce ongoing repairs and maintenance. Alectra Utilities expects that these investments will help avoid increases in operating expenses, replace end of life systems and equipment, and ensure compliance with legislative requirements such as the AODA.

Building renewal is also needed to continuously improve Alectra Utilities' business practices and systems. Other investments in this DSP, such as the information technology ("IT") investments in collaborative tools and workforce mobility rely on appropriately and efficiently configured workspaces. The Facilities Management investments focus on addressing the issues affecting of Alectra Utilities' facilities, including building envelopes, security systems, and equipment, to enable Alectra Utilities' core business to operate reliably, efficiently and in compliance with legislative and regulatory requirements.

Table A17 - 1 presents a summary of the facilities management investment as well as drivers and outcomes.

Table A17 - 1: Facilities Management Investment Expenditures, Drivers and Outcomes

	Historical Spending				Bridge	Forecast Spending				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$11.6	$4.8	$5.2	$1.4	$3.7	$4.2	$2.6	$2.9	$4.6	$3.5
Primary Investment Driver:	System Maintenance and Capital Investment Support									
Secondary Driver:	Reliability, Safety, Failure Risk									
Investment Outcomes:	Reliability, Safety, Efficiency, Customer Value, Reliability, Environment									

II Investment Description

The planned Facilities Management investments are required to ensure that Alectra Utilities is able to plan, execute, and support critical utility functions, on a 24/7 basis. These investments ensure that Alectra Utilities' operating and administrative infrastructures such as IT systems, control rooms, operations centers and work offices serve Alectra Utilities customers and respond to operational demands, especially in response to emergencies. These investments will also ensure that all Alectra Utilities' facilities comply with applicable regulatory standards, including safety requirements that protect Alectra Utilities' employees and the public.

During the DSP period, Alectra Utilities' focus is to: (i) increase physical security by adding/replacing cameras, yard fencing upgrades and card access at required sites; (ii) optimize work spaces by introducing: Alectra Utilities new office and furniture standards that are smaller and more efficient than predecessor utilities, projects to support accessibility requirements; and (iii) enhance the consistency and efficiency of space utilization across the utility.

The following sections summarize Alectra Utilities' planned expenditures on Facilities Management during the DSP period. The drivers of each category are set out in Section III – Investment Drivers and Need below, along with the major deficiencies that are addressed by the planned investments.

2.1 Security/Life Safety

Security/Life Safety enhancements are necessary to protect Alectra Utilities' employees and assets as well as the general public using updated security systems and measures.

Alectra Utilities plans to replace some legacy surveillance cameras and implement inventory yard access control and security enhancements (including upgraded fencing) to prevent security breaches such as thefts. Alectra Utilities also plans to update security infrastructure and consolidate all facility security management software and integrated intrusion/access systems to improve efficiencies and security levels. To deter unauthorized entries unto the utility's premises, Alectra Utilities plans to update locking hardware, card readers, fencing, gates, security lighting and other available solutions and tools.

All Security/Life Safety activities will be migrated to single access control, access security and surveillance system. This migration will enable the consolidation of security administration and access control functions to one central location. Alectra Utilities also plans to upgrade its physical key systems.

The update of security/life safety work in facilities is expected to yield the following benefits:

- Eliminate systems failures by replacing and of life systems;
- Provide visual deterrents (i.e. presence of security systems) to potential crimes;
- Improve employee and public safety;
- Protect Alectra Utilities physical assets such as inventory, IT equipment and furniture;
- Streamlined processes through the consolidation of five legacy security systems to improve response times and monitoring activities;
- Prevent the increase of operating expenses associated with the maintenance of aging security systems;
- Assist in evidence gathering where incidents require investigation; and
- Prevent unauthorized access to restricted areas.

Over the 2020-2024 DSP period, Alectra Utilities plans to spend approximately $17.8MM on these investments.

2.2 Generators/Elevators

Specific elevator systems in Alectra Utilities' buildings have not undergone modernization or major upgrade since their installation and have exceeded their TUL. Along with the required elevator updates, some of the lifting devices will also need the installation of elevator car top railings.

Emergency generators are required to provide back-up power for critical 24/7 functions such as Alectra Utilities' control rooms, operations centres and facilities housing IT infrastructure. To maintain the utility's operational continuity and restoration capability, back-up power supplies via emergency generators is urgently required. During the DSP period, specific emergency generators are at the end of their useful life and are in need of a major overhaul. Certain emergency generators require replacement over this planning period. Alectra Utilities will consult with the relevant emergency generator suppliers to ensure all replacement units are fuel efficient and properly sized to meet the applicable building and operational systems demand.

2.3 Building Heating Ventilation Air Conditioning ("HVAC") Systems

Certain HVAC systems within Alectra Utilities' facilities have not undergone modernization or major updates since their installation and have exceeded or will soon exceed their TUL. Some HVAC systems have experienced prolonged outages due to the lack of parts required for repair, resulting in increased operating and maintenance expenses as well as negative impacts on the day to day work environment of Alectra Utilities employees. Alectra Utilities plans to renew HVAC systems for some of the buildings, which will replace the units with energy saving models and contribute to ensuring the utility's overall reliability, safety and operational readiness.

2.4 Building Deficiencies

Alectra Utilities plans to address issues affecting the building envelope (in particular, brick masonry walls, windows and roofs) at various locations. This component of the investment will focus on end-of-life assets that are becoming increasingly costly and problematic to maintain. More specifically, the investment will address exterior walls/curtain walls, roof structures/roofing which includes replacement of the Built-up Roof (BUR) System and BUR canopy, window/door replacement which includes failed insulated glass units, repairs and sealants replacement, corroded structural steel members and building brick repointing. Also, Alectra Utilities plans to carry out required roof replacements at Nebo Road and Patterson operating centers since the relevant assets are deteriorated, leaking and will exceed their typical useful life within the 2020-2024 period.

2.5 Building Outdoor Walkways/Driveways

Alectra Utilities plans to address issues regarding outdoor walkways and driveways. In particular, interlocking walkways, sidewalks and paving of parking lots at various facilities require renewal to reduce the risk of accidents for employees and the general public and ensure adequate storm water management during rainstorms.

2.6 Building Space Renewal

During the DSP period, Alectra Utilities plans to renovate a number of its building sites to maximize the efficient use of current office space.

Certain Alectra Utilities facilities required renewal investment necessary to meet regulatory building codes and standards such as accessibility and fire code requirements. External requirements, codes and standards have been incorporated with Alectra Utilities' internal standards to ensure consistency in design, heating and cooling, and lighting into facility sustainment investments. Application of facility standards will result in facility support efficiencies, right-sizing of inventories (i.e., spare furniture and equipment), operational savings, and enable interoperability across the utility's facilities.

Alectra Utilities also plans to renovate several of its work spaces to create more open and interactive work spaces, reduce office and workstations sizes and introduce multiple uses of spaces for increased productivity, efficiency and workflow. To minimize the total cost of ownership, Alectra Utilities' facility management plans repurpose as much of existing assets and materials by working closely with furniture manufactures to modify existing instead of purchasing all new, cabinetry in kitchenettes/printing rooms and other assets and materials based on conditions and financial benefits.

2.7 Summary of Investment Benefits

Table A17 - 2 summarizes the outcomes and benefits associated with the Facilities Management investments.

Table A17 - 2: Facilities Management Investment Outcomes and Benefits

Investment Benefits	Reasoning and Investment Benefits
Reliability	• Sustainment of emergency facility assets ensures business continuity to mitigate risks to system operations and ensure system reliability during emergency event response.
Customer Value	• Alectra Utilities requires to address security and facility issues to ensure that employees are adequately equipped to provide timely and effective customer service.
Safety	• Security enhancements will deter potential authorized intrusions and theft from Alectra Utilities premises and improve employee and public safety.
Environment	• Removal of any hazardous substances (e.g. asbestos, vermiculite, lead) that may be identified. • Separation of demolition materials metals etc. for disposal where applicable. • Utilization of energy efficient assets such as lighting, HVAC, and other appliances that will contribute to lower energy use and operating costs.
Efficiency	• Improve worker productivity and efficiencies across the organization through the application of facility standards and updated workspaces to optimize and streamline work practices and address identified ergonomic issues. • Renewal of end-of-life facility assets such as HVAC, lighting, building envelopes to present day building codes will reduce operating costs. • Addressing obsolescent systems which are not functional and unreliable such as security systems and HVAC/boiler equipment.

III Investment Drivers and Need

3.1 Purpose

The main purpose of the Facilities Management investments is the renewal of specific facility assets that are at end-of-life, reduce potential safety risks to employees and the public, to mitigate operating risks, mitigate potential damage to other assets, and increasing maintenance costs, if not addressed proactively, could adversely impact the utility's core business operations.

Alectra Utilities maintains three corporate offices and seven service centres totalling over one million square feet of space with the Alectra Utilities territory. Alectra Utilities owns and maintains buildings and assets ranging in age from 10 years old to 70 years old. To ensure that it was properly maintaining and making the best use of these diverse facilities, Alectra Utilities and other utilities rely on experts to evaluate their buildings and identify needed capital investments. In 2013, Alectra Utilities' predecessor Horizon Utilities Ltd. retained Evans Consulting Services to assess the facilities in for the west region. In 2018, Alectra Utilities retained Pinchin Ltd. to assess the facilities in the central and east regions (collectively, the "Expert Assessments").

As part of the Expert Assessments, teams of specialists inspect each system or asset in Alectra Utilities' buildings to understand their condition. This review is extensive, encompassing all mechanical, electrical, plumbing and architectural elements in a building. The experts assessed the facilities' condition was based on any deficiencies and the remaining useful life of the system. The Expert Assessments provide an overall facility/asset condition, recommended budget, and replacement schedule. This information was a key input in preparing the repair and renewal investments set out in this portfolio.

The planned Facilities Management investments are required to support Alectra Utilities' day-to-day activities which include workflow collaboration, customer service, communications, employee productivity and engagement. These investments also include renovations to some facilities, such as reclaiming storage or common space, reduce office spaces to generate required office space to bring employees and operations together to improve productivity and streamline processes and activities. Proper meeting spaces are also required to assist with collaboration and combined with the application of technology, minimize travel time between locations.

Facility management investments also include necessary building infrastructure and component renewals, including replacement of end-of-life assets such as windows, roofs, elevators and HVAC systems. Alectra Utilities will also consolidate legacy security systems into an integrated control and monitoring platform across all of its facilities, thereby reducing operating expenses and enhancing the utility's ability to respond to emergencies and restore power to customers.

The planned Facilities Management investments are needed to address a range of risks and operational requirements, as summarized below:

- **Security/Life Safety:** Risks of physical security intrusions due to limitations in existing security systems, including (i) reaching end-of-life and experiencing operational constraints, (ii) difficulty in sourcing required replacement parts for repairs, (iii) inability to accommodate additional security card requirements, and (iv) technical limitation of legacy systems constraining the implementation of present day security requirements.
- **Generators/Elevators:** Generator and elevator asset infrastructure that have reached their end-of-life criteria and must be replaced or upgraded to present day safety and regulatory standards.
- **Building HVAC:** Outdated HVAC systems at end-of-life pose significant risks and constraints to the working environments and conditions of Alectra Utilities employees. The persistent failure of systems increases maintenance and repair costs. In some cases, replacement materials are no longer available or difficult to procure.
- **Building Deficiencies:** Risk of failure of key building components (e.g., roofs, windows, ceilings), requires Alectra Utilities to address deteriorated assets to minimize safety risks to employees and other components of the facility, assets and critical operational systems secured within. For example, water damage, as shown in Figure A17 - 1 to Figure A17 - 3, may introduce mould as well as permanent damage to the foundation and building structure.

Figure A17 - 1: Water Damage of Wall at John Street Building

Figure A17 - 2: Water Damage Nebo Road Roof

Figure A17 - 3: Water and Salt Damage of Wall at Sandalwood Parkway Building

- **Building Outdoor Walkways/Driveways:** These investments will address current accident and flooding risks due to deterioration and operational issues affecting various walkways, driveways and drainage systems.
- **Building Renewal:** Alectra Utilities plans to reorganize the layouts of its work centres to maximize efficient use of the building footprint as well as employee resources. These investments will also enable greater collaboration between employees at multiple sites, which reduces the safety and environmental risk inherent to the significant amount of road travel that some staff currently take between sites.

Table A17 - 3: Investment Drivers

Investment Driver	Reasoning and Investment Benefits
Primary Driver: System Maintenance and Capital Investment Support	Alectra Utilities' facilities house functions that are essential to the effective and efficient operations of all elements of the utility's business, including the planning and execution of maintenance and capital work. Specific building assets have reached the end of typical useful lives and are no longer supported by the vendor. Failure of deteriorated or end-of-life building assets can hinder the execution and productivity of Alectra Utilities' business functions, and may directly impact Alectra Utilities' ability to respond effectively to power interruptions or emergencies.
Secondary Driver: Failure Risk	Alectra Utilities' facilities have components that have reached typical useful lives and are obsolete. Maintenance costs for deteriorated and obsolete assets are expected to continue to increase over time.
Secondary Driver: Reliability	The capital investment program is required to help ensure that all operation centres and administration buildings operate as required. HVAC systems and back-up generators are reaching condition and age where major repairs or replacements are required. Security systems are not consistent across all of the Alectra Utilities' facilities introducing interoperability challenges and gaps in processes.
Secondary Driver: Safety	Alectra Utilities' facilities continue to require investments in security infrastructure enhancements and upgrades to help eliminate potential dangers and threats to the public and Alectra Utilities' personnel and property.

The following subsections detail the major deficiencies that the facilities management investments will address.

3.1.1 Security/Life Systems Issues

Under the Security/Life Safety component of the investment, Alectra Utilities will implement up-to-date security systems and measures which are necessary to protect the employees, general public and assets. Currently, Alectra Utilities operates four legacy access control and access security systems (i.e., Chubb AFX, Keyscan, Honeywell and General Electric) that manage ten primary facilities. The current surveillance system consists of Pelco, Avigilon, IRAS and Omnicast systems. Many of these systems are failing, and parts are difficult to obtain creating security concerns. Also, existing systems cannot support the required demand and volumes of the business.

3.1.2 Generators/Elevators

Assessments of generator and elevator facilities identified a need to renew certain elevator and generator systems.

Some of the elevator systems serving specific Alectra Utilities buildings have not undergone modernization or major upgrades since system installation, and have reached their useful life expectancy, and specific elevators (e.g., freight elevator at the Nebo Road service centre) have experienced prolonged outages due to difficulty in procuring replacement parts and support services. To address these issues, as well as to meet current regulatory standards, Alectra Utilities must undertake upgrades to specific elevator systems. Capital expenditures planned fro the coming years is to upgrade, replaced or/and modify these assets based on the findings and recommendations from assessments conducted by third party service providers and revised Technical Standards and Safety Authority (“TSSA”) Regulations.

Due to the age of the assets, condition and increasing operational concerns, in 2017, Alectra Utilities retained Rooney, Irving and Associates to assess the elevator systems at the John Street and Vansickle buildings in the West Operating Area. This assessment focused preliminary on elevators assets and was conducted in addition to the building assessments conducted by Evans Consulting in 2015. The objective of the assessment was to determine the condition of the equipment, develop sustainment requirements and options and identify the necessary updates to bring the elevators into compliance with present day elevator code requirements. As the freight elevator systems at John Street facility were installed in 1952, the units were not fitted with ascending car over speed and unintended car movement protection. This feature is often provided in the form of rope brakes, dual brakes or counter weight safeties which prevent the elevators from over speeding in the up direction or moving away from a landing with doors open in certain instances. The assessment also identified the lack of cooling in the motor room which increases the risk of motor failure. Due to the condition and the obsolescence of the machine, motor and controller, Alectra Utilities plans to renew the end-of-life freight elevators at John Street and bring the units into compliance with present day codes.

3.1.3 Building HVAC System

HVAC is important for reliability, safety and operational readiness. Some of the HVAC systems within Alectra Utilities' buildings have not undergone renewal since their installation and have reached the end of their TUL. HVAC failures introduce direct and immediate adverse impact on the working environment and conditions for Alectra's employees and business operations, particularly during hot summer days or cold winter days. Repairing older units may not possible due to the lack of available replacement parts or cost prohibitive nature of the repair. Certain Alectra Utilities' buildings have poor air quality and environmental conditions. Also, existing HVAC systems were not designed with the capacity to handle the current operating levels of employee and equipment occupancy, which place stress on the HVAC systems and accelerate the deterioration of the assets into early failure. In response, Alectra Utilities plans to replace specific HVAC units with energy efficient models. The replacement units are specified to present day energy efficiency level and will provide reduced operating costs.

3.1.4 Building Deficiencies

The Expert Assessments identified priority issues that were deemed to pose immediate safety and operational concerns (such as brick masonry repairs, replacement of windows and roofs) at various locations. For example, the exterior of the John Street office consists of a stone facing, brick veneer and granite strip. There is cracking and surface staining on the stone facing and granite strip, which will need to be maintained, while the brick veneer is in poor condition with deteriorated, stained and damaged bricks. The BUR system and BUR canopy at the Patterson facility are original to the date of construction, deteriorated and approached the typical useful life with a need to be renewed. The roof at the Nebo Road facility has a significant number of water leaks due to multiple penetrations through the current roofing membrane. Alectra Utilities has determined that long term maintenance of the roof overlay system is very difficult and plans to renew the roof. Such roof repairs will reduce the need to perform interior repairs in response to ongoing water leaks, lessen the adverse impact to employees' working conditions, prevent damage to assets from water leaks, and reduce labour coast associated with water leaking response and repairs.

3.1.5 Outdoor Walkways/Driveways

Alectra Utilities plans to address issues affecting the outdoor walkways, driveways, and parking areas (in particular, interlocking walkways, sidewalks and paving of parking lots) at specific facilities. Notable items to be addressed through this work include the following:

- Driveways and walkways erode with use and exposure to weather elements, causing catch basin sink holes and the potential for a trip and fall accident for employees and the general public.
- John Street underground parking is need of repairs and updating to reseal and resurface the parking area. The floor membrane is not properly adhered to the floor and allows water to pool under the member, leading to further damage to the concrete floor. The membrane has exceeded the useful life and requires renewal. The ramp leading down to the basement is also in poor condition and need of renewal.
- Facilities management investment include the ongoing repairs and localized replacement of the asphalt pavements throughout the 2020-2024 planning period. Asphalt pavement at various locations of the Mavis Road facility indicates alligator/linear cracking, deterioration, cracked and uneven settlement. Such conditions are common for the nine facilities that Alectra Utilities operates, but the Mavis facility has been prioritized for renewal. Asphalt pavement renewal will ensure staff and public can travel safely and that Alectra Utilities can respond to emergencies promptly. This work will reduce the risk of accidents for employees and the general public and improve storm water management during rain storms.

3.1.6 Building Space Renewal

The layouts of Alectra Utilities' work centres must be reorganized and optimized to maximize efficient use of building footprint, as well as employee resources. Currently, significant travel between office sites is a daily necessity for many staff to perform their duties and meet with their relevant teams, manage and supervise staff across multiple locations. Many departments do not currently have the office space capacity (within their current footprint) for the centralization of all departmental employees. Some buildings are beyond capacity, putting a strain on building systems and parking at these buildings. Certain departments that were required to be consolidated and centralized at a single location following the merger were set up in temporary spaces occupying meeting rooms with obsolete cubicles that need to be replaced.

IV Investment Timing and Pacing

4.1 Summary of Expenditures

Table A17 - 4 provides the year-over-year breakdown of Facilities Management investments, including the historical period from 2015-2018, the 2019 bridge year, and the DSP period from 2020-2024.

Table A17 - 4: Historical and Proposed Facilities Capital Investment

	Historical Spending				Bridge	Forecast Spending				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$11.6	$4.8	$5.2	$1.4	$3.7	$4.2	$2.6	$2.9	$4.6	$3.5

4.2 Historical Expenditures (2015-2019)

Capital expenditures between 2015 and 2019 total $26.7MM, with an annual average of $5.3MM. Capital expenditures between 2015 and 2019 focused on building and building assets renewals between ten facilities, totalling over 1,000 square feet of space. Capital expenditures focused on assets that had surpassed end of life and were negatively affecting other assets and overall operations, removal of hazard materials, new or/and revised regulation requirements and safety risks. They included window and roof replacements, removal of asbestos from older buildings such as John Street, retrofit facilities to comply with the Accessibility for Ontario with Disabilities Act (AODA), repairs to buildings envelope and security systems replacements or/and upgrades.

4.3 Future Expenditures (2020-2024)

Alectra Utilities' future expenditures have been developed based on three areas of focus:

4.3.1 renewal of building infrastructure;
4.3.2 reactive capital projects, and
4.3.3 capital replacement investments.

4.3.1 Renewal of Building Infrastructure

Alectra Utilities maintains three main offices and seven service centres ranging in age from 10 years to 70 years old, totalling over one million square feet of space within Alectra Utilities territory. Many of the building infrastructures were designed to be built to meet operations and customer requirements of the time and cannot support today's operation requirements without building renewal efforts. In addition, many of the buildings were built based on the standards of the time and materials used are consider a risk to employees today. Many portions of the buildings are still original and have not had any major renewals. During the last three years some efforts has been made to some of the buildings infrastructure and assets based on third party service assessments findings and recommendations, but more efforts is required in the coming years to buildings renewal for Alectra Utilities to continue to provide a safe and reliable work environment for its employees and customer support. The forecasted capital expenditures for building renewals are to address some of the major risk to the operations, Alectra Utilities employees and the public in the coming years. Below, details on the most significant building renewal project planed between 2020 and 2024:

Patterson Road Roof Replacement Project

The objectives of the project planned for 2024 at the Patterson Road service centre located in Barrie, are to replace of the building roofs that have exceeded the projected useful life. Various decaying roof conditions identified need to be addressed to prevent further damage to the building envelope, structure and assets.

Other expected objectives and outcomes include:

- Reduce wind scouring conditions;
- Address water ponding;
- Address corrosion on the metal guardrails and exterior metal ships ladder;
- Address cracked and split/de-bonded goose neck vent sealants;
- Replace roof to eliminate conditions that lead to moisture on the precast concrete wall panels;

Project Summary

Pinchin Ltd. was retained by Alectra Utilities to conduct a Baseline Property Condition Assessment (BPCA) in 2018. The report states that the roofing systems are original to the date of their construction in 1990 (i.e., approximately 28 years old) and have exceeded their Projected Useful life (PUL). The report concluded that the Patterson Road service centre building have reached their end of life and that recommended that the roofing systems be replaced to prevent any further damage to the building structure systems and other assets. Replacing this roofing system will result in increased efficiencies, prevent future deterioration of the assets, and reduce repairs and maintenance costs.

The roof replacement will include upgrades to the current building code, improvements to the roof insulating values. Alectra will investigate the best replacement roof type for this facility to maximize the useful life of the building.

Due to the solar panels located atop the upper roof system, labor costs associated with removal of the solar panels from the roof system prior to the roof replacement program as well as installation of the solar panels subsequent to the roof replacement program.

4.3.2 Facilities Reactive Capital Expenditures

Alectra Utilities maintains three main offices and seven service centres totalling over one million square feet of space with the Alectra Utilities territory. Facilities reactive capital projects focus on restoring equipment or adding equipment/assets to maintain normal operations after a breakdown to ensure business continuity. To accomplish this, replacement of faulty parts and or components/assets will be required. These forecasted expenditures are to address unforeseen and unbudgeted asset replacements or net new asset investments as a result of an assessment outcome or regulatory requirements.

The objectives and outcomes of this work are:

- Maintain normal business operations to support customer needs;
- Address safety concerns;
- Address unforeseen asset renewal;
- Address office space requirements;
- Address audit findings.

Examples of possible unforeseen capital reactive projects:

- HVAC Systems and components
- Security systems
- Life safety systems
- Items to address deficiencies from audits or assessments

4.3.3 Facilities Capital Replacement Investments

The objectives of these projects are to maintain the buildings, assets and systems in a condition that contributes to maintaining efficiencies, business operations and to alleviate pressure on the operating expenditures. Capital Replacement refers to an expenditure that is based on the condition and/or lifecycle of a given building or component/asset and is scheduled for replacement (e.g. condenser, furnace, windows, roofing).

The objectives and outcomes of this work are:

- Improved energy performance of buildings systems and infrastructure;
- Maintain normal business operations to support customer needs;
- Reduce maintenance/breakdown costs;
- Improved employee safety;
- Extend the life of other supporting assets.

Projects Summary

Alectra Utilities maintains three corporate offices and seven service centres totalling over one million square feet of space with the Alectra Utilities territory. Alectra Utilities owns and maintains buildings and assets ranging in age from 10 years to 70 years old. In order for Alectra Utilities to better understand facilities capital investment/replacement needs in all its buildings, Facility Condition Assessments ("FCA"s) were completed. In 2013 Evans Consulting Services was retained to conduct an FCA for the west region and Pinchin Ltd. was retained by Alectra Utilities to conduct a Baseline Property Condition Assessment ("BPCA") very similar to an FCA in 2018 in the central and east regions.

These FCAs involved a team of one or more specialists inspecting each system/assets in the buildings to understand its condition. These include all mechanical, electrical, plumbing and architectural elements in a building. The condition is based on any deficiencies and the remaining useful life of the system. With this information, Alectra Utilities was able to determine the timing of system repairs and renewals. The FCA provides an overall facility/asset condition, recommended budget and replacement schedule, enabling Alectra Utilities to budget the proper level of investment required.

As a result of these FCAs, Alectra Utilities has identified the following projects that will be completed over the next five years in each of its facilities based on the highest return on investment and mitigation of risk to the operations;

- Replacement Heating, Ventilation and Air Conditioning ("HVAC") systems;
- Upgrading emergency generators;
- Upgrade and modernization of passenger and Freight elevators
- Roof replacements and repairs
- Asphalt replacements and repairs
- Window replacements
- Repairs to exterior building envelopes
- Security surveillance and access control system upgrades

4.4 Execution Approach

The planned Facilities Management investments between 2020 and 2024 have been determined based on the FCAs, known conditions, regulatory requirements, potential safety risks and operational requirements. Alectra Utilities' approach to executing such investments are based on the following guidelines and factors:

- Approved capital expenditures;
- Required external and internal resources availability;
- Additional findings not originally identified or/and known during the project;
- Asset conditions;
- Operational requirements;
- Safety risks;
- Regulatory compliance;
- Engineering, design, and permits activities;

Expenditures are executed based on an approved business case and a project team consisted of internal and external resources. Qualified contractors and service providers will perform all work once the scope, schedules, resources availability and final cost has been established. All projects will be sourced and purchased based on Alectra Utilities Procurement Policy and Processes. Alectra Utilities must plan and secure required capital budget years in advance to maintain its building assets in proper operational order.

V Options Analysis

Alectra Utilities has considered the following options concerning Facilities Management investments:

- Status Quo;
- Prioritized, Risk-Based Approach.

5.1 Status Quo

Under the status quo option, facilities assets would continue to deteriorate impacting operations, damaging other assets, increasing operating expenditures, increasing safety risks and not in compliance with regulations and standards. As set out in the sections above, the facilities investments planned during the DSP period are driven by serious risks and issues, as assessed by third party experts. Alectra Utilities cannot accept the status quo approach, since it would allow these risks and issues to continue and potentially worsen.

5.2 Prioritized, Risk-Based Approach

Under this option, planned investments are prioritized base on risks. Alectra Utilities' planned facilities investments for the next five years have been assessed and prioritized based risks to operations, employees, public, assets conditions and financial impact to our customers. Third party physical assessments findings and recommendations were used as the base to this approach. Alectra Utilities has taken this approach to identify the required capital investments.

VI Investment Projects

The facilities material investments from 2020 to 2024 that form the Facilities investments are included in Table A17 - 5. With the exception of the Patterson Road service centre building roof replacement planned for 2024, the remaining planned facilities investments are being planned between multiple years due to the number of required resources, impact to the operations and customers and number of facilities within Alectra Utilities territory.

Table A17 - 5: Facilities 2020 to 2024 Material Projects and Initiatives

Project Code	Project Name	CAPEX ($MM)
150738	Buildings Capital Replacement Investment Support	$7.9
150741	Facilities 2024 Replacement Patterson Road Roof	$1.2

Appendix A18 - Information Technology Systems

I Overview

Alectra Utilities relies on secure, effective, well-supported Information Technology ("IT") systems to plan and execute distribution system work, and to respond to the needs of its customers. During the DSP period, Alectra Utilities plans to invest in several IT systems. As described in this evidence, these investments are primarily to renew systems that would otherwise be unsupported, and to renew deteriorated equipment.

The planned IT Systems investments fall into four categories:

1. **IT Software** – Software used to deliver customer-facing and internal services. During the DSP period, Alectra Utilities plans to invest in:
    - The Meter-to-Cash System to bill and collect from customers;
    - The Operational Software for outage response and capital investment planning/execution;
    - The Enterprise Resource Planning ("ERP") system which is a central financial tool for the utility; and
    - Other Core Applications that Alectra Utilities relies on to operate (e.g., operating systems and other software).
2. **IT Hardware** – Physical and virtual hardware Alectra Utilities uses to operate the utility. During the DSP period, Alectra Utilities plans to invest in:
    - Control Room Technology including servers and SCADA systems;
    - Network, Storage, and Computation such as servers, local area networks, data storage, and physical data centres; and
    - End User Technology including desktop computers, laptops, virtual thin clients, and field devices.
3. **IT Security** – Alectra Utilities must maintain cyber-security systems that are sufficient to meet evolving cyber-security risks. The planned Security investments are necessary to protect customer and employee information as well as align Alectra Utilities' systems with

the requirements of the Ontario Cyber Security Framework ("Security Framework").[161] During the DSP period, Alectra Utilities plans to make Security investments in:

- Cyber-security Devices Upgrades; and
- Foundational Governance and Security Services.

4. **Business Optimization** – During the DSP period, Alectra Utilities plans to invest in critical technologies including:
    - Service Optimization to enhance business unit platforms and applications for business units outside of IT (such as on the Communications and the Protection and Control platform); and
    - Business Support for ongoing business requirements (such as IT Service Management support, asset registry and data analytics).

Table A18 - 1: Information Technology Systems Investment Plan, Drivers and Outcomes

	Historical Spending				Bridge	Forecast Spending				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$24.8	$9.2	$5.0	$4.8	$10.2	$15.1	$18.2	$19.8	$12.3	$8.4
Primary Driver:	System Capital and Maintenance Investment Support									
Secondary Drivers:	Functional Obsolescence									
Outcomes:	Efficiency, Customer Value, Reliability, Safety, Cyber Security and Privacy, Coordination and Interoperability, Environment									

[161] On March 15, 2018, the Ontario Energy Board amended the Transmission System Code and Distribution System Code requiring licensed electricity transmitters and distributors in Ontario to report on their cybersecurity preparedness relative to the newly-established Ontario Cyber Security Framework. The code amendments define "cyber security" as "a body of technologies, processes, and practices designed to protect networks, computers, programs, data and personal information from attack, damage or unauthorized access", and reference both electronic and physical security.

II Investment Description

This section summarizes planned investments in Alectra Utilities' IT Systems over the 2020 to 2024 period.

2.1 IT Software

Alectra Utilities' investment in software is required to meet customer service expectations, and to provide systems needed to ensure enterprise applications are efficient, reliable, and able to scale with the growing utility. These investments are also necessary to ensure that data remains secure and accessible, and protected against ongoing cyber-security threats. Finally, Alectra Utilities must ensure that its software systems are able to respond to evolving regulatory and compliance obligations.

During the DSP period, Alectra Utilities must ensure IT software systems are scaled and maintained to efficiently manage core business operations and processes to execute planned work on the distribution system and customer-facing services.

Alectra Utilities' planned software investments during the DSP period are as follows:

Table A18 - 2: Software Investments

IT Software Investments	Total 2020-2024 ($MM)
2.1.1 Meter to Cash System	$29.7
2.1.2 Operational Software	$7.1
2.1.3 Enterprise Resource Planning	$8.7
2.1.4 Core Applications	$3.5
Total	**$49.0**

2.1.1 Meter-to-Cash System

Alectra Utilities' Meter-to-Cash System is a suite of related systems used to provide efficient and accurate meter readings and billing services.[162] The Meter-to-Cash System is integral to Alectra

[162] The Meter-to-Cash System includes the following sub-systems: Meter Readings, Advanced Metering Infrastructure ("AMI"), Meter Data Management, Wholesale and Retail Settlement, Electronic Business Transactions, Meter Data Management and Repository ("MDM/R"), Billing, Payments, Credit and Collections, Business Intelligence, and Reporting (and related field activity). All these systems and

Utilities' relationship with its customers, including customer service,[163] billing and related services,[164] retail transactions and settlements, and wholesale settlement with the Independent Electricity System Operator. During the term of the DSP, Alectra Utilities plans to invest approximately $29.7MM in the utility's Meter-to-Cash System, as set out in Table A18 - 3.

Table A18 - 3: Meter-to-Cash System Investments for 2020-2024

Project	Total 2020-2024 ($MM)
CC&B Update	$13.3
CC&B Oracle License Renewal	$3.0
CC&B Enhancements	$10.4
Updates to systems ancillary to CC&B	$3.0
Total	**$29.7**

The Oracle Customer Care and Billing ("CC&B") Platform is Alectra Utilities' primary enterprise system for billing and customer care. This system holds the master records used for billing, customer records and contact information, current and historical billing meter reads, metering installation data, and all other transactional data relating to customers. The CC&B system allows Alectra Utilities to provide accurate bills, respond to inquiries from customers, manage customer contact and moving data, and to track field services and activities associated with metering and other equipment.

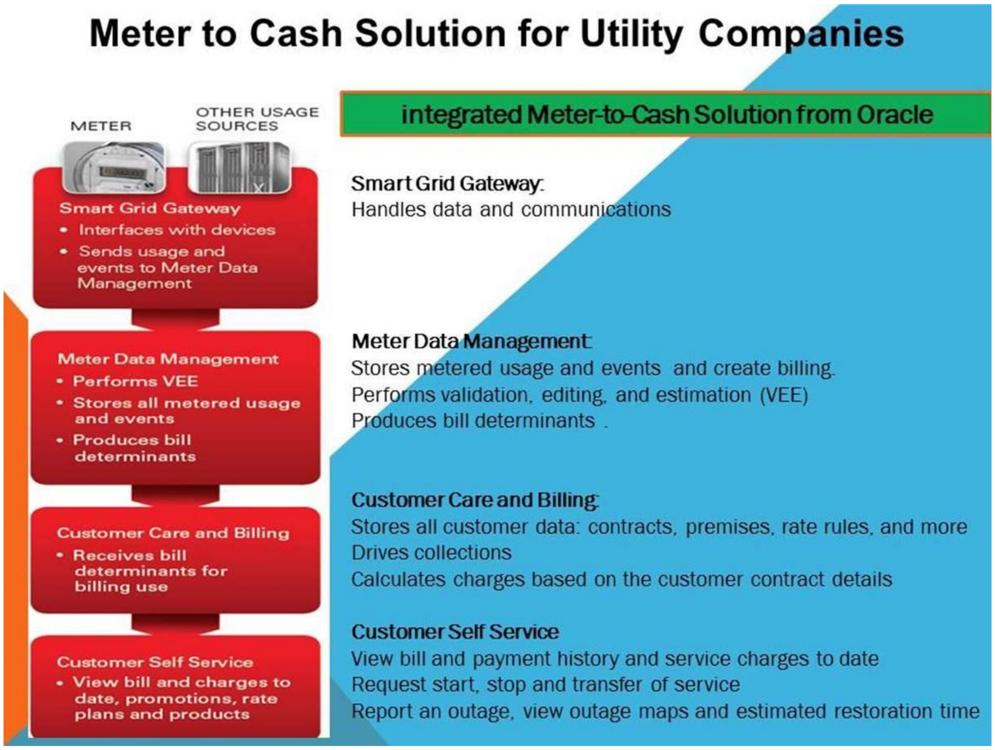
Most of the planned expenditures in the Meter-to-Cash System relate to updating critical software to current versions and preparing the systems to accommodate customer expectations and experience. Without the proposed update to these systems, this core system would be exposed to unacceptable reliability and cybersecurity risks. Alectra Utilities plans to implement ongoing security and system patches while vendor support is still available. Figure A18 - 1 illustrates the multiple systems that comprise the meter to cash solutions and the interaction processes between each system.

processes are supported by a host of interfaces and underlying technology, including complex monitoring tools, databases and enterprise service buses.

[163] Customer account management, service location management, and customer contact functions are all integrated with the Meter-to-Cash System.

[164] Including credit and collection, metering, and billing (including complex billing for embedded and wholesale market participants).

Figure A18 - 1: Meter to Cash Solutions for Utilities



A CC&B Update

Alectra Utilities plans to invest $13.3MM to update to the current version of the CC&B software between 2021 and 2022. Without the investment to update, the utility's current version of CC&B is no longer supported by Oracle. As a result, newly released security patches are not available, the risk of software failure increases, and issues may arise due to incompatibility with other updated ancillary systems. Upgrading to the current version of the software is necessary to continue vendor support, maintain compliance with regulatory requirements and other systems, and support cyber-security.

B CC&B Oracle License Renewal

Alectra Utilities plans to renew its unlimited license agreement ("ULA") with Oracle, to ensure its licenses remain active past the expiration date of 2020. This will come at a cost of $3MM .The licenses allow Alectra Utilities to use the CC&B platform and related data. Renewing the ULA will also provide necessary support for security, automated database backups, ongoing database infrastructure operations, and access to new functionality from Oracle. Renewal of the ULA for

Oracle CC&B is the most cost-effective option to standardize licenses relating to the underlying database and associated tools. If Alectra Utilities were to licence CC&B without the ULA, would result in an additional annual expenditure of $2.4MM for compliance with Oracle's licensing framework.

C CC&B Enhancements

During the DSP period, Alectra Utilities plans to enhance CC&B to improve its performance and to comply with regulatory requirements. These enhancements introduce process optimization and enhanced customer experience. For example, added functionality includes Smart Meter systems which provide better data accuracy and integrity, quicker responses to customers evidenced by improved phone call metrics. The enhancements will cost $10.4MM over the DSP period. Alectra Utilities' focus is on providing customers with the flexibility to choose their preferred touch points and channels to increase the overall customer experience.

Throughout the term of this DSP, Alectra plans to review and optimize processes and systems that will enhance the customer experience and increase utility effectiveness. This includes:

- Touch point enhancements to increase customer knowledge and satisfaction;
- Investments in digital channels including e-billing, payment processes, and self-service web forms; and,
- Technology upgrades to enable real-time communications between field agents and Alectra's Customer Care agents.
- The review and streamlining of Alectra's touchpoints will improve the overall customer experience by ensuring clear and consistent messages and refined processes, regardless of channel. This includes both its digital platform and traditional touch points including telephone conversations, face-to-face interactions, faxes, web services, e-mail and traditional mail and printed materials such as invoices and billing inserts.

Alectra will continue to invest in its payment channels, in particular electronic payment methodologies which provide convenience to customers and automated processes for the utility. Currently Alectra's electronic payment offerings include pre-authorized payment, online or internet banking, credit card payments.

Despite an increasing customer transition to electronic payment channels, adoption levels to receive electronic billing remain low with only 16% of customers receiving their bills electronically. This can be compared to industry peers who have optimized their services for customers to achieve penetration rates in excess of 25%. New e-billing services will be implemented to streamline the registration process, enhance the delivery model, and promote this "best practice" service. Alectra sees the potential to achieve 25% or greater e-billing adoption within 5 years with investment and promotion of its services.

D Updates to Systems Ancillary to CC&B

Several systems run parallel to the CC&B platform and require investment through the DSP period. These include Advanced Metering Infrastructure ("AMI") systems, Meter Data Collection Systems, the Oracle Load Profiling and Settlement System ("LPSS"), ITRON MV-90 Interval Data Collection platform, and Atomic Application Scheduling Platform. Alectra Utilities plans to deploy a new customer self-service system, allowing customers to conduct an expanded range of activities through the utility's website. The system will allow customers to manage transactions, move-in/move-out requests, customer name changes, and billing/account inquires through platforms of their choice. The website will provide tailored energy management advice and will integrate with available energy management initiatives. This investment will include increased automation to the back-end processes that power the customer website, removing manual input and increasing the speed that services are provided to customers. Automating more services on Alectra Utilities' website and billing engine, will free customer service time for more complex customer issues.

- Planned investments include providing new digital technologies to field crews and customer service representatives. This will allow Alectra Utilities to improve customer service, safety, and operational efficiency. These systems will allow staff to securely review live data as they interact with customers or execute work on-site. With real-time data, Alectra Utilities will deliver better service and mitigate potential safety risks. For personnel in the field, these systems will provide information about the customer and distribution equipment at the customer's premises. For customer service representatives, customer data will be available from CC&B, which will provide customers with a better experience when interacting with Alectra Utilities. These investments will cost $3.0MM through the DSP period with most of the costs ($2.2MM) incurred in 2020 and 2021.

2.1.2 Operational Software

Alectra Utilities' Asset and Outage Management systems are key tools in Alectra Utilities' approach to planning work on distribution assets and outage planning. During the term of the DSP, Alectra Utilities plans to invest approximately $7.1MM in the utility's Asset and Outage Management systems. Specifically, Alectra Utilities plans to update its Geographic Information System ("GIS") and Outage Management System ("OMS"), and to introduce a Workforce Management System ("WFM").

Table A18 - 4: Operational Software Investments for 2020-2024

Project	Total 2020-2024 ($MM)
GIS and OMS	$2.4
WFM	$4.7
Total	**$7.1**

A Geographic Information System and Outage Management System

The GIS is the central repository for data on the distribution assets that Alectra Utilities uses to serve customers. The GIS informs Alectra Utilities what assets exist within its system, where they are located, and how they connect to the larger distribution system. It contains all asset registry data (including nomenclature, asset nameplate, type and class), all smart meter and associated customer data, and all connectivity data (including primary and secondary connections). The GIS is central to Alectra Utilities' ability to diagnose, plan, and respond to issues on the distribution system. All planned capital work is based on data within the GIS.

Alectra Utilities' power system controllers use the OMS to store all relevant data associated with planned and unexpected outages. Key features of the OMS include providing a centralized record of outage response data and of details on the restoration steps during an outage event. The OMS also records core reliability data for outages on Alectra Utilities' distribution system, including customers interrupted ("CI") and customer hours interrupted ("CHI") for each outage event.

Expenditures on GIS and OMS are forecast to total $2.4MM spread relatively evenly from 2020 to 2024. The updates planned for GIS and OMS during the DSP term will help ensure that the individual platforms for GIS and OMS continue to have the required security, data and functionality support to meet customer needs in terms of service reliability. By continuing to perform the necessary updates to the GIS and OMS, Alectra Utilities is ensuring that these systems are supported by the vendor and receive the necessary patches and security updates. Enhancements to the system are based on business needs in order to maintain data integrity, data security and data access as processes are improved and streamlined. Keeping pace with updated technologies requires enhancements to the GIS.

B Workforce Management System

During the DSP period, Alectra Utilities plans to introduce a new WFM to manage the utility's field crews. Through these investments, Alectra Utilities expects to reduce the complexity of managing resources and work scheduling, improve field practices, obtain better data on the status of work and crew performance, and enhance the customer experience. WFM is a computerised tool to schedule and assign field work, allocate resources, and track the progress of field work.

The WFM tool will streamline workflows by interfacing with various systems to reduce the number of sources of work for field crews, issue work electronically, and enable field crews to digitally perform tasks such as job updates, time entry, and material ordering. Supervisors and clerical staff will work in a single system to assign work, manage crew schedules, and track job progress. The streamlining of sources of work, and the number of systems that staff have to work in, will yield benefits in terms of Field Supervisor and crew productivity. The projected productivity improvements are expected by avoiding manual efforts on allocating resources for daily work, reduced travel time and cost through improved work organization and improved scheduling and tracking of short-duration work. The WFM solution will provide a tool where crew schedules and job progress will be visible in real-time.

While the primary benefit of WFM lies in the management of shorter-duration work, the solution will also yield benefits in the field-management of larger capital projects. As is the case with short-duration work, field supervisors rely on a variety of systems to determine personnel and equipment availability, and then assign or reassign resources on a day-to-day basis.[165] A multitude of discrete activities take place over the course of a longer-duration project, but there is currently no common system in place to create detailed project schedules or track these activities. Field supervisors rely primarily on paper-based processes and documents to manage projects, and there is no real-time visibility into crew activities or job progress.

The planned WFM system will use information from the master schedule to manage field activities and resources at a more granular level, and provide field supervisors with a computerised tool for resource allocation, crew management, and field activity scheduling. The addition of the WFM tool will further enhance project scheduling and execution, which in turn will further improve Alectra Utilities' ability to manage execution of its Capital programs. During the 2020-2024 DSP period, Alectra plans to invest $4.7MM in the WFM system. The scope of the WFM project will include implementation of a digital tool to schedule work and allocate resources, digital dispatch functionality of work to field crews, development of real-time tracking of work progress and tracking of crew schedules, digital recording and transmission of field data as well as dispatch route automation.

2.1.3 Enterprise Resource Planning

The Oracle JD Edwards ("JDE") Platform is Alectra Utilities' primary enterprise system for financial reporting and integrated data recording. Using JDE, Alectra Utilities is able to manage multiple business processes including those associated with capital and operational expenditure, employee lifecycle, finance and estimation routines, as well as asset registry and nameplate data. During the DSP term, Alectra Utilities plans to invest approximately $8.7MM to update the JDE system with the most recent Oracle features that will allow it to effectively integrate with other utility systems responsible for critical functions such as time-keeping and monitoring compliance with safety requirements.

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[165] Alectra Utilities uses an enterprise system called P6 (Primavera) to track and report on the progress of larger capital projects. The utility uses capital program information from another system, C55, to build a master schedule of larger capital projects to be executed over the course of the year. Alectra Utilities also tracks project progress via P6. Projects are issued via the PDG to individual field supervisors or contractors to be executed. P6 is a valuable tool for managing and tracking the progress of the master schedule at a higher level, but crew management is very much a manual process.

Table A18 - 5: ERP Investments for 2020-2024

Project	Total 2020-2024 ($MM)
JDE Hardware Upgrades	$0.6
JDE Enhancements	$8.1
Total	**$8.7**

A JDE Hardware Upgrades

Alectra Utilities plans to invest $0.6MM to upgrade the JDE hardware in order to maintain reliability on the ERP infrastructure.

B JDE Enhancements

Alectra Utilities plans to invest $8.1MM to implement Oracle feature releases to the current version of the JDE software between 2020 and 2024. Maintaining the reliability and integrity of this critical business system is essential for the recording and reporting of data. During this 5 year period, application and security related feature enhancements will be released by the vendor as part of the software support process. Without strict adherence to this continuous innovation release process, security patches, support and software enhancements will not be implemented, resulting in the risk of software failure, disruption to business processes, non- compliance to regulatory requirements, cyber security exposure and compatibility issues with third party applications and systems. Such disruptions will affect Alectra Utilities' financial, vendor, and employee processes and the ability to report accurate information in line with regulatory requirements. Implementation of these planned Oracle releases to the ERP platform will allow Alectra Utilities to expand the capabilities of the system by integrating new modules or add-ons into the core ERP system.

With the implementation of these Oracle releases Alectra Utilities plans to integrate the ERP with other core IT systems. Integration enhancements will facilitate exchange of information between systems, mitigate the status-quo risks of manual input errors, simplify data points, and improve reporting capabilities to assist decision-making. Enhancements will address core business processes such as regulatory compliance, timekeeping, health and safety functionality, asset analytics.

The ERP system is a critical business system and as Alectra Utilities continues to deploy new assets and new technologies, it is necessary to ensure business functions and processes adapt to and evolve within the platform.

Enhancements to ERP includes the creation and implementation of the following:

- interface to Alectra Utilities' Applicant Tracking system;
- system for fieldworkers to enter time electronically;
- system to track Alectra Utilities' distribution assets throughout asset lifecycle;
- system to determine optimal inventory levels through production planning and inventory control;
- system to automate daily IESO invoicing, and
- interface to IT Service Management System for employee on-boarding and off-boarding.

Enhancements to the ERP will streamline processes, allow for more accurate and detailed end user reporting, reduce overtime, reduce manual entry, and leverage ERP functionality.

2.1.4 Core Applications

Core Applications are the front-end software Alectra Utilities uses on a day-to-day basis. Alectra Utilities pays to license and update this software. While the specific applications that require expenditures vary from year to year, the overall level of spending on Core Applications is relatively stable. Key software that is covered by the Core Applications portfolio include:

- Operating Systems (e.g., Microsoft Windows Server / IBM-AIX / Linux),
- Core cloud-based office platforms (e.g., Microsoft Office 365/SharePoint Online/One-Drive),
- Analytics and Infrastructure Monitoring,
- Automation and Orchestration Tools, and
- Enterprise Asset Register and Optimization Platform.

Where it is cost-effective, Alectra Utilities also updates these core applications to versions that offer new features that create value for the increasing demands of the new utility workforce and customer base. The benefits of such updates range from improved security, reliability, effectiveness and efficiency. Alectra Utilities is also planning to adopt certain cloud-based applications that allow personnel to have access to the same tools and systems no matter where they are located or where service is required. The benefits of each planned investment are summarized in the accompanying business case summaries.

During the term of the DSP, Alectra Utilities plans to invest approximately $3.5MM in the utility's Core Applications.

Alectra Utilities' spending on Core Applications is primarily to update existing applications. Spending trends on Core Applications is consistent with prior years.

2.2 IT Hardware

Alectra Utilities must update its IT hardware on a regular basis to ensure the reliable performance of systems supporting customer-facing services, core distribution operations, and other important processes. IT hardware assets include core backend infrastructure (such as servers, networked storage and communication systems), endpoint assets (such as desktops, laptops, field devices and printers), and security appliances.

IT Hardware assets support systems that are used to manage field crews and respond to outages, and thus are critical to the utility's ability to meet operational outcomes, including reliability. Should this hardware fail, the company would be unable to perform key tasks, harming Alectra Utilities' ability to respond to outages and otherwise manage the distribution system.

IT Hardware underpins the utility's environmental, health, and safety processes across work centres and job sites. Processes include completion of site condition and safety forms, safety and environmental audits, and incident and claims investigations. In the event of an IT hardware or software failure, employees may not have access to the information required to make informed decisions about environmental and health and safety issues. Such issues may be serious and time-sensitive, thus potentially compromising work safety or contributing to inadvertent breaches of safety requirements.

Alectra Utilities reviews its IT Hardware standards regularly, based on the utility's requirements from operational, regulatory, security and customer service perspectives. As Alectra Utilities implements new technology, related software and hardware must be updated to keep pace. By replacing end-user hardware that is older than five years or out of warranty, Alectra Utilities can generally avoid IT equipment breaking down during normal business functions. Replacing obsolete equipment reduces support time, downtime and maintenance costs associated with older equipment. New equipment also allows Alectra Utilities to take advantage of technological advances in both software and hardware to provide a platform that is more able to support customer-facing business initiatives while fortifying the utility's cyber-security.

During the DSP period, Alectra Utilities plan to renew approximately 1800 endpoint assets, (such as such as desktops, laptops, field devices and printers) and approximately 650 core backend infrastructure assets (such as servers, networked storage and communication systems).

Alectra Utilities replaces most IT hardware based on lifecycle management practices considering the expected lifespan of each category of hardware asset in order to mitigate functional obsolescence. As the end of a hardware asset's lifecycle approaches, the risk of failure increases significantly which then impacts core business processes.

During the DSP period, Alectra Utilities' planned hardware investments are divided into the following categories:

Table A18 - 6: IT Hardware Investments for 2020-2024

Project	Total 2020-2024 ($MM)
2.2.1 Control Room Technology	$2.7
2.2.2 Network, Storage and Computation	$9.4
2.2.3 End User Technology	$6.3
Total	**$18.4**

2.2.1 Control Room Technology

From 2020 to 2024 Alectra Utilities plans to invest in replacing room control room technology nearing the end of its useful life, and to update systems as required to meet the needs of the increasingly automated digital distribution system. The main investments planned for Control Room Technology from 2020 to 2024 are to update components of the Supervisory Control and Data Acquisition (SCADA) system, and to replace servers nearing the end of their useful life. During the DSP term, Alectra Utilities plans to invest $2.7MM in the utility's Control Room Technology.

Alectra Utilities' control room requires technology to support its day-to-day distribution activities. This includes backbone servers of data associated with the OMS and SCADA systems, computer displays and radios and handsets. These systems allow power system controllers to monitor, isolate and restore activities across the distribution system to ensure its safe operation.

SCADA is crucial to the control room, providing real-time readings from the field associated with outage events. It allows power system controllers to control SCADA-enabled devices at the substation or distribution asset level to control outages and restore service to customers. During the DSP period, Alectra Utilities plans to update the hardware used to operate the SCADA system, and standardize the SCADA interface.

Current control room hardware is updated in order to continue to manage the increasing level of data that flows into the control room, creating longer outages for customers and potential safety risks for crews and the public. Data from Alectra Utilities' GIS is used in the control room to control the distribution system during customer isolation and restoration procedures.

When hardware lacks the specifications required to support that flow of information, there can be a lag between the power system controllers' instructions and the reaction of the device in the field. That lag can result in longer outages and, in some cases, it can create a safety risk. If a field crew needs to work on distribution assets, they need to know whether the assets are energized. If there is a lag between the times a power system controller sends a signal to a switch and when the switch actually responds, the field crew may not be certain whether the assets are still energized.

The planned hardware and software updates to the SCADA system include updates to the control room maps used to communicate real-time information on Alectra Utilities' distribution system, and the screens at the power system controllers' workstations. The updated screens and workstations will allow Alectra Utilities to better manage and display the increasing volume of information that flows to the control room. The new workstation hardware covered by this program will be designed to manage additional data volume and will mitigate the risk of potential lag between the controllers' actions in the control room and the response of SCADA-enabled devices in the field.

The Control Room Technology expenditures will also fund replacement of end-of-life servers which manage the data of the OMS and SCADA systems. Alectra Utilities' current control room servers will be unable to meet the needs of the increasing volume of SCADA-enabled feeders on the utility's evolving distribution system. As more SCADA-controlled and automated switches are added to Alectra Utilities' distribution system, the control room systems require greater processing power and storage to manage the volume of data from equipment in the field.

2.2.2 Network, Storage, and Computation

Alectra Utilities must regularly replace back-end hardware devices to support the daily operation of the utility and provide the foundation expected from our employees and customers as the utility moves to supporting the technological needs of a modern utility. The Network, Storage, and Computation investments will replace standard hardware that has reached its end-of-physical-life as part of the normal life-cycle management of these assets. Through the DSP period, Alectra Utilities plans to invest $9.4MM in the utility's Network, Storage and Computation systems.

Planned Network, Storage and Computation investments are to renew the following equipment:

- Physical servers, which enable services for the web, individual applications and databases;
- Data storage devices, including storage area networks and disk storage arrays; and
- Data networking devices, including routers, switches, firewalls, load-balancers and wireless access points.

Alectra Utilities' network relies on this backbone hardware to operate reliably and securely. Physical servers store critical data relating to Alectra Utilities' assets, and confidential customer and operational data. Individual data storage devices allow Alectra Utilities personnel to maintain and create storage locations for key initiatives and projects. Data network devices allow Alectra Utilities employees to continually access physical servers and data storage devices.

Alectra Utilities replaces Network, Storage, and Computation hardware as part of the normal life-cycle management of IT assets. This approach is cost-effective and allows the utility to maintain its core business processes and functionality. Replacing end-of-life hardware ensures Alectra Utilities' IT infrastructure remains reliable and avoids the increasing maintenance costs and lost productivity that results from extended use of old hardware.

Relying on outdated hardware increases costs and delays to system restoration when failures occur as vendor warranties expire. Replacing outdated hardware is evaluated to determine whether the investment is made in physical, virtual, or cloud-based infrastructure, to allow the utility to manage larger environments as a result of the changing utility landscape, customer experience, and new application services.

2.2.3 End User Technology

Alectra Utilities relies on a range of end-user technology to carry out day-to-day operations. These assets are a range of standard IT equipment, such as computers, printers and mobile technology used in offices and in the field. During the DSP period, planned investments in End User Technology will allow Alectra Utilities to enhance the security and mobility of the utility's end user technology. During the term of the DSP, Alectra Utilities plans to invest approximately $6.3MM in the utility's End User Technology Computing systems. This planned investment spending is relatively stable year-over-year and is consistent with past levels.

Alectra Utilities regularly replaces technology used by office and field staff, consistent with asset-life cycle management practices. Alectra Utilities replaces desktop, laptop and mobile devices that are five years old or older, as well as desktop printers and other end user hardware. It is impractical for the organization to continue relying on technology past its useful life – as the performance and reliability of hardware degrades the level of support required increases significantly, as do maintenance costs and lost productivity. In addition, vendor warranties expire at or before five years, further compounding the cost of supporting aging technology assets.

To evolve both security and mobility with the Alectra Utilities end user computing platform, Alectra Utilities will adopt a "virtualization first" approach for all desktop and application deployment. This will allow Alectra Utilities to move to a more flexible and secure virtualized environment at a cost that is consistent with past spending.

Alectra Utilities also plans to replace printers as part of the normal replacement cycle, with the goal of adopting centralized printing solutions and thereby reducing the total number of printers across all of its geographic locations.

2.3 IT Security

Alectra Utilities' distribution system requires increasing investment to respond to growing cyber-security risks. These risks have many sources, including the accelerating adoption of new technology both within utilities and behind-the-meter. These technologies lead to many benefits, but they also increase the risk posed by cyber-security threats. Alectra Utilities must have the appropriate systems to identify and respond to the security risks that are inherent to an increasingly inter-connected distribution system. Investments in IT Security are designed to enhance the hardware and software infrastructure within Alectra Utilities in order to protect the operation of the utility's distribution system, protect confidential customer and employee information, and to satisfy the requirements of the Security Framework.

During the DSP period, Alectra Utilities' planned IT Security investments are divided into the following categories:

Table A18 - 7: IT Security Investments for 2020-2024

Project	Total 2020-2024 ($MM)
2.3.1 Cyber Security Devices Upgrades	$1.4
2.3.2 Foundational Governance and Security Services	$2.4
Total	**$3.8**

2.3.1 Cyber-security Device Upgrades

Alectra Utilities plans to invest $1.4MM to replace obsolete security appliances such as firewalls and network access control devices ("NAC") between 2021 and 2024. The firewalls guard against cyber threats to both corporate and operational technology networks. The investments in NAC devices will provide enhanced visibility and control of both wired and wireless devices connecting to Alectra Utilities' network.

Alectra Utilities must replace obsolete firewalls since the utility's current firewalls will no longer be supported by the vendor. As a result, security patches will not be available, the risk of system reliability increases due to inevitable cyber-attacks, and compatibility issues may arise. Without full vendor support, any disruption caused by a system failure is likely to take longer to resolve resulting in additional costs and delays to correct the failure. Security and data integrity compromises are inevitable.

Alectra Utilities must invest in modern NAC equipment to effectively manage network access particularly from the proliferation of mobile computing devices, and increased business reliance on third-party service providers. The planned investments in NAC systems will strengthening of Alectra Utilities' network security by:

- Providing tighter controls surrounding access to Alectra Utilities' network environments through creation and maintenance of an accurate inventory of authorized devices (wired/wireless) accessing the network;
- Providing the capability to detect and control network access by unauthorized devices;
- Effectively controlling access to the utility's network by external network assets (contractor, vendors, etc.);
- Providing the ability to perform a cyber-security interrogation check on a network-based assets prior to granting access to the network; and
- Allow Alectra Utilities to more effectively measure its cyber-security posture.

2.3.2 Foundational Governance and Security Services

During the DSP period, Alectra Utilities plans to invest $2.4MM for new foundational governance and security services. These investments include the development of key capabilities including basic features and scope to provide the minimum protection to Alectra Utilities' Information Technology systems. These include database security, application governance, and network segmentation to limit the risk of exposure. Software and hardware purchases are required as part of this investment in order to protect customer, employee and Alectra Utilities' information.

These risk-based investments are critical to protect Alectra Utilities' corporate and customer information and are not considered discretionary. Investing in foundational governance and security will allow Alectra Utilities to:

- Reduce security risks to Alectra Utilities' data, application, infrastructure and business processes;
- Provide capability to manage, detect, protect, respond to and recover from security attacks;
- Harden the utility's security posture; and
- Avoid consequential impacts from potential security incidents such as private data leakage or system disruptions leading to power outages.

2.4 Business Optimization

Through the Business Optimization portfolio, Alectra Utilities intends invest in technologies that will allow employees to work more effectively. During the term of the DSP, Alectra Utilities plans to invest $2.6MM in these Business Optimization Projects.

Investments in this portfolio include:

Table A18 - 8: IT Business Optimization Investments for 2020-2024

Project	Total 2020-2024 ($MM)
2.4.1 Service Optimization	$0.4
2.4.2 Business Support	$2.2
Total	**$2.6**

2.4.1 Service Optimization

During the DSP period, Alectra Utilities plans to invest approximately $0.4MM in Service Optimization. These expenditures will include enhancing Alectra Utilities' customer communications and interactions. As new web technology becomes available – enhancements to the website will be updated accordingly – providing higher service quality to customers.

Implementation of Doble PowerBase will facilitate the utility's management and reporting on protection assets maintenance and engineering records.

2.4.2 Business Support

The Business Support initiative focuses on technology improvements that will allow Alectra Utilities to manage and track assets, and enhance employee productivity through improved communication and meeting room technology. Over the DSP period, Alectra Utilities plans to invest $2.2MM in Business Support.

A primary Business Support investment during the DSP period is to develop an enterprise asset register application. This application will support Asset Management requirements to manage and track movement of assets, asset demographics, equipment failures, and support asset condition assessments and business case modelling.

Other planned Business Support expenditures are primarily to install enhanced collaboration tools at Alectra Utilities' work centres. Alectra Utilities also plans to implement minor updates and upgrades to the tools used to deliver and manage IT services within the company.

Alectra Utilities plans to improve its ability to collaborate across the utility's expansive service territory by installing systems in meeting and collaboration rooms at the utility's facilities. Currently, the utility's meeting rooms have a range of different presentation and communication equipment, impeding remote collaboration. The planned investments include centralized systems for meeting scheduling and communication technologies in meeting rooms, such as enhanced screen to screen video conferencing and wireless connections for computer connectivity.

Alectra Utilities plans to replace aging projector and telephone systems with a standard package that includes shared video, audio, and white board systems.

In addition to operating efficiencies and work effectively, Alectra Utilities expects these improved collaboration tools will result in safety and environmental benefits. Given the disparate locations of Alectra Utilities' work centers, better remote collaboration will reduce the need for staff to commute from one work centre to another. By keeping cars off the road, Alectra Utilities will avoid risks to employee safety and reduce the environmental impact of the utility's administrative functions.

Alectra Utilities also plans to upgrade the systems it uses to track IT-related issues, respond to service requests and otherwise manage the IT needs of the company. Alectra Utilities' IT systems include hundreds of servers, thousands of user accounts across multiple systems, and various cloud-based solutions. Managing this complex range of systems manually is increasingly inefficient with the status-quo. By adopting automated solutions, Alectra Utilities can deliver IT services more efficiently and securely.

2.4 Summary of Investment Outcomes and Benefits

Table A18 - 9 summarizes the overall outcomes and benefits associated with the Information Technology Systems portfolio.

Table A18 - 9: Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Efficiency	These investments will provide productivity benefits including: • New digital technologies reduce downtime and data input error, and provide more accurate and reliable outputs • Common processes across the entire organization ensure consistent service delivery • Elimination of redundant and duplicate software • Introduction of new software functionalities to automate existing manual processes and practices • Introduction of new hardware to provide more power and speed to handle more complex tasks and assignments as well as to minimize downtime • Enhanced communication technologies allowing employees to remain within their work centres and teleconference remotely (as opposed to physically driving to alternate work centres) • Control room technology upgrades will yield significant efficiency improvements, resulting in improved performance for customers. Alectra Utilities plans to transition to a system where switches will be programed by software (rather than manually). This approach will allow the utility to adjust new circuits in minutes rather than hours.
Customer Value	These investments will provide value to the customer including: • Enhanced customer experience (online and with customer service) • Faster services to customers due to modernized systems • Enhanced cyber-security protection to secure sensitive customer and employee information and mitigate the risks of data intrusion and theft
Reliability	These investments will provide reliability benefits including:

Outcome	Investment Benefits and Objectives
	• Enhancements to control room technologies will expedite outage restoration activities • Continued investments in enterprise systems such as GIS, ERP and OMS ensure that asset data is the most up-to-date and that decision-making to prioritize assets for intervention is as accurate as possible, thus allowing for the mitigation of outage events • Up-to-date IT software and hardware ensure Alectra Utilities can continue to manage the system both proactively (to prevent outages) and reactively (to restore customers as quickly as possible) • The upgrade and replacement of communications equipment that is beyond end of useful life will mitigate the risk of equipment failure and prolonged outages (since the control room will not be able to respond to outages without the requisite communications equipment) • The implementation of new communications hardware in conjunction with modern network protocols as part of a complex network will enhance Alectra Utilities' communications capabilities, eliminating the delays (up to 20 minutes between actions by control room operators and actual responses on the system) that can occur in the existing communications hardware and multiple route redistribution protocol • The implementation of more robust cyber-security protections to minimize the probability of reliability impacts resulting from acts of cyber-security or other network intrusions
Safety	These investments will provide safety benefits including: • Replacement of end-of-life communications hardware ensures improved remote control of SCADA-enabled distribution

Outcome	Investment Benefits and Objectives
	assets, minimizing delay between control room operations and corresponding isolations/energization in the field, reducing potential safety risk to field crews engaging with those assets • Upgrades to enterprise systems and databases ensures that asset data integrity is maintained and field crew workers can operate and maintain the system with the most up-to-date information, thus mitigating safety risks • Enhanced teleconferencing technologies improve collaboration and communications as we arrange meetings connecting from multiple locations at once , eliminating the need to travel between work centre to work centres and the accompanying safety risks • Introducing the necessary security protections will mitigate the risk of data and system intrusion, which (if not prevented) may result in the catastrophic failure of electrical equipment (e.g., in the event of a major cyber-attack affecting a substation) and potentially pose a safety risk to Alectra Utilities crews as well as the general public
Cyber-security and Privacy	These investments will provide cyber-security and privacy benefits including: • Maintaining current enterprise applications including CC&B, GIS, ERP and OMS ensure that the most up-to-date security patches have been applied and that data remains secure • Upgrading of IT hardware ensures that the threat of data intrusion and theft is mitigated as hardware remains supported • Security initiatives will allow Alectra Utilities to align with the Security Framework, and ensure that appropriate protections for sensitive and private /personal data are put into place
Co-ordination / interoperability	Maintaining the most current and up-to-date IT software and hardware increases interoperability and compatibility between

Outcome	Investment Benefits and Objectives
	physical assets, communication systems and the associated software
Environment	These investments will provide environmental benefits improvements including enhanced teleconferencing technologies allow employees to better communicate between work centres, without the need to travel, reducing environmental impacts

1

III Investment Drivers and Needs

The IT Systems portfolio is designed to manage the Alectra Utilities' legacy hardware, software and other technology infrastructure. This involves regular maintenance/replacement and strategic enhancements. Alectra Utilities relies on this portfolio to operate its distribution system in a safe, secure and efficient manner. Aging technology products comprising this portfolio introduce risks to the utility; they are at or near their support end-of-life criteria. Alectra Utilities plans to replace software and hardware assets that are at or beyond their useful lives.

When IT hardware and software are no longer regularly supported with the latest updates, they become functionally obsolete. This means that this technology can no longer maintain compatibility with the hardware in the field or with current policies and practices.

It would not be prudent for Alectra Utilities to continue to operate using hardware that is beyond its useful life or software that is no longer supported by the vendor. Without support from the vendor, Alectra Utilities is not able to easily modify the legacy software or hardware to support new processes and procedures within the utility. In addition, without vendor support, applications would not be subject to patching which provides enhancements and security features to protect data and the integrity thereof.

Since Alectra Utilities is not in the business of developing software or hardware, in-house customization of old software or hardware in order to support new functions within the utility is virtually always uneconomical. Where Alectra Utilities can purchase extended support for older systems, the support is generally cost prohibitive. Even with extended support, ongoing use of older technology may result in other issues such as increased data security risk. As such, it is essential for Alectra Utilities to continue to update and enhance its software and hardware to ensure that the utility is capable of delivering electricity and services to its customers in a safe, secure, reliable and efficient manner.

For the reasons described above, the primary driver of this program is System Capital and Maintenance Investment Support, and the related secondary driver is Functional Obsolescence. These drivers are further detailed in Table A18 - 10.

Table A18 - 10: Investment Drivers

Investment Driver	Reasoning and Investment Benefits
Primary Driver: System Capital and Maintenance Investment Support	All system capital and maintenance investments depend on enterprise systems, including IT hardware, software, communications, security, and underlying databases that support these systems.
Secondary Driver: Functional Obsolescence	Legacy IT hardware and software is functionally obsolete as it no longer has support from vendors. Without vendor support, Alectra Utilities is no longer able to maintain and update the systems in a cost-efficient manner, which makes these technologies needlessly vulnerable to failure, data integrity corruption and security breaches. Obsolete systems do not receive necessary security upgrades.

IV Investment Timing and Pacing

4.1 Summary of Expenditures

Table A18 - 11 provides the year-over-year breakdown of IT Systems investments, including the historical period from 2015-2018 and the 2019 bridge year, and the DSP period from 2020-2024.

Table A18 - 11: Historical and Proposed Investment Spending

	Historical Spending				Bridge	Forecast Spending				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$24.8	$9.2	$5.0	$4.8	$10.2	$15.1	$18.2	$19.8	$12.3	$8.4

4.2 Historical Expenditures (2015-2019)

Historical expenditures between 2015 and 2019 total $54.0MM. IT Systems expenditures were relatively consistent over the historic period, subject to the following exceptional spending:

- Elevated capital spending in 2015 was driven by the $10MM cost of replacing the Customer Care and Billing system in Alectra Utilities' eastern operating area, and updating to Windows 10 in Alectra Utilities' western operating area at a cost of $2.5MM.
- Actual IT systems expenditures in 2016-2019 were materially higher than shown in Table A18 - 11 due to the exclusion of merger-related transition costs from any figures in this DSP.
- Alectra Utilities' eastern operating area spent an additional $2.6MM in 2016 to update Customer Care and Billing to comply with the OEB mandate to issue monthly bills by the end of 2016.

Table A18 - 12: Historical Projects 2015 to 2018 and Bridge Year 2019 ($MM)

Categories ($MM)	2015	2016	2017	2018	2019	Total
Core Applications	$1.1	$0.4	$0.2	$0.0	$0.8	$2.5
Enterprise Resource Planning	$2.2	$0.5	$0.1	$0.1	$1.1	$4.0
Network, Storage, and Computation	$1.3	$0.8	$1.1	$0.7	$1.7	$5.6
Meter-to-Cash Systems	$13.1	$3.7	$0.9	$1.3	$2.5	$21.5
Control Room Technology	$0.7	$0.1	$0.0	$0.0	$0.2	$1.0
Business Optimization	$0.5	$0.1	$0.0	$0.0	$1.8	$2.4
Operational Software	$0.9	$1.2	$0.4	$0.4	$0.3	$3.2
Foundational Governance and Security Services	$0.0	$0.0	$0.3	$0.4	$0.3	$1.0
End User Technology	$4.5	$2.3	$2.0	$1.8	$1.3	$11.9
Cyber Security Devices Upgrades	$0.0	$0.0	$0.0	$0.0	$0.2	$0.2
Asset and Outage Management	$0.5	$0.1	$0.0	$0.1	$0.0	$0.7
Total	**$24.8**	**$9.2**	**$5.0**	**$4.8**	**$10.2**	**$54.0**

4.3 Future Expenditures (2020-2024)

Expenditures between 2020 and 2024 are forecast to be $73.8MM. Significant IT Systems cost drivers during the DSP period include:

- **2020-2021:**
  - $1MM is required for JDE ERP Enhancements in 2020 in order to provide urgently needed integration between the ERP system and other core utility systems.
  - The Oracle ULA is required to be renewed in 2020 in order to maintain the required Oracle licenses essential for Alectra Utilities' Oracle systems. Maintaining the Oracle ULA requires annual expenditures of approximately $1.5MM in both 2020 and 2021.
- **2021-2022:**
  - Planned updates to CC&B will cost $6.5MM in 2021 and 2022.
- **2022-2023:**
  - Implementation of JDE ERP system feature enhancements will cost $1.8MM in 2022 and 2023.

- Workforce Management Software is planned to be installed in 2022, with a forecast cost of $2.3MM in 2022 and 2023.

Table A18 - 13: Planned Investment Projects 2020 to 2024 ($MM)

Categories ($MM)	2020	2021	2022	2023	2024	Total
Control Room Technology	$0.1	$1.4	$0.8	$0.3	$0.1	$2.7
Core Applications	$0.9	$0.8	$0.6	$0.9	$0.3	$3.5
End User Technology	$1.2	$1.4	$1.4	$1.6	$0.7	$6.3
Enterprise Resource Planning	$2.0	$1.1	$2.4	$1.8	$1.4	$8.7
Network, Storage, and Computation	$2.8	$1.6	$3.2	$1.0	$0.8	$9.4
Operational Software	$0.3	$0.4	$2.7	$3.3	$0.4	$7.1
Meter-to- Cash System	$5.6	$10.0	$8.1	$2.4	$3.6	$29.7
Cyber Security Devices Upgrades	$0.0	$0.2	$0.0	$0.6	$0.6	$1.4
Foundational Governance and Security Services	$0.6	$0.8	$0.4	$0.3	$0.3	$2.4
Service Optimization	$0.2	$0.1	$0.1	$0.0	$0.0	$0.4
Business Support	$1.4	$0.4	$0.1	$0.1	$0.2	$2.2
Total	**$15.1**	**$18.2**	**$19.8**	**$12.3**	**$8.4**	**$73.8**

4.4 Investment Pacing and Prioritization

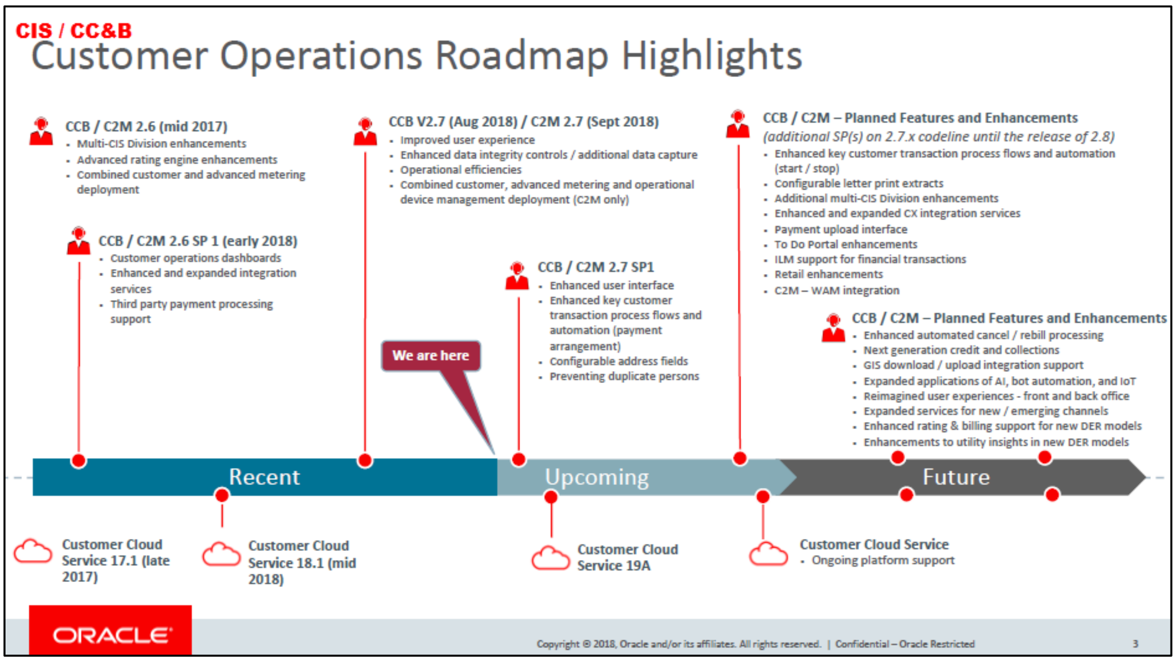
As described in Section 5.4.1 of the DSP, Alectra Utilities uses CopperLeaf C55 capital investment system to optimize investment portfolios based on values and risk. The investment portfolio is optimized based on the available funding, the project value, and the company's risk matrix. Pacing and prioritization across the IT Systems investments varies for each investment.

Prioritization considers business needs and vendor support agreements (in terms of upgrade requirements for the larger enterprise systems). For Alectra Utilities Enterprise Systems (i.e., Meter-to-Cash and ERP) the vendor roadmaps and vendor specifications provide investment direction in terms of updates and feature release enhancements. These guidelines ensure the optimal amount of vendor support, enhancements to maximize benefits of the systems and security patches to maintain and protect data and information.

Pacing of projects ancillary to enterprise systems such as CC&B and ERP and projects to update hardware to support these systems are adjusted for implementation timing based on compatibility, business requirements and integration sequence of systems.

The timing and pacing of other IT hardware and software projects is based on functional obsolescence and asset lifecycle; this enables Alectra Utilities to maximize asset value and mitigate risks of asset failures. Figure A18 - 2 illustrates the roadmaps of the CC&B systems.

Figure A18 - 2: CIS/CC&B Roadmap



4.5 Execution Approach

Alectra Utilities' planned approach to IT Systems varies for each investment. Alectra Utilities' IT department will execute most of the projects associated with these investments in the IT Systems. Alectra Utilities' project management office will assist in ensuring that each investment is tracked and managed. The utility must perform day-to-day operations while projects are executed; Alectra Utilities will ensure that its project plans ensure that resource constraints are minimized so the utility's operational requirements are not negatively impacted.

For most investments, Alectra Utilities has relevant expertise internally to deliver the projects on-time and on-budget. Based on the need of a particular investment, Alectra Utilities may engage third party partner to validate the necessary configuration and/or changes. The third party may also assist in implementing the change, depending on its complexity and staff availability. Third party resources typically fill Alectra Utilities' technical knowledge gaps or augment internal resources.

V Options Analysis

Alectra Utilities' capital planning process ensures the utility selects options that deliver the greatest long-term value for the utility's customers.

Expenditures in the IT Systems portfolio primarily consist of version updates to pre-existing systems for support, security, and functionality. In cases where there is no reasonable alternative to staying current with vendor support model these options must be implemented in a planned and staged manner.

As the systems below are highly specialized and customized, when considering alternatives, there were few feasible options other than the proposed investment or maintaining Alectra Utilities' status-quo.

- **IT Software:**
  - **Status Quo:** By maintaining the status-quo on IT Software systems, Alectra Utilities would not benefit from process improvements and enhancements issued with updates, feature release enhancements and upgrades that drive efficiencies and meet new business demands. Without updates, vendor support, system fixes and security patches to protect customer information and data integrity would be compromised or unavailable, and system reliability may be compromised. System failures and potential prolonged restoration to address issues could significantly affect Alectra Utilities' operations and its ability to deliver service to customers and execute planned work programs.
  - **Option 1 (selected option):** Alectra Utilities maintains upgrades and software applications to support business- and customer-facing applications. By maintaining upgrades on software, Alectra Utilities would avoid the risks associated with operating without vendor support. It would also benefit from associated improvements, security patches and system fixes that come with upgrades that in turn drive efficiencies, improve processes and meet new business demands.
  - **Option 2:** An alternative to updating software to current versions would be to purchase extended support from the vendor, if available. Alectra Utilities has

determined that this option would not deliver value for Alectra Utilities or its customers, since:

- Extended support, if available, comes at a higher cost than upgrading,
- Vendors cannot guarantee the full support required, and
- Security and system patches depend on other components such as the operating system, software version, and other factors. These other components are often outside of the software vendors' control.

- **IT Hardware:**
  - **Status Quo:** Operating on older technology, Alectra Utilities would be subject to the risk of equipment failure, higher maintenance costs, and possible business process disruption. Lack of vendor support on older equipment compromises Alectra Utilities' cyber-security and could affect the quality of service delivered to customers through Alectra Utilities' customer-facing and business applications. This approach is more reactive in nature and could have short-term capital benefits but the risk of operating on equipment that is nearing functional obsolescence poses mores risks and disadvantages than advantages.
  - **Option 1 (selected option):** Alectra Utilities maintains and controls its IT infrastructure to support customer-facing services, core distribution operations and other business processes. Maintaining these assets ensures operations perform on reliable systems, securely, and with a low risk of failure. As Alectra Utilities implements new technology, related software and hardware must be updated to keep pace. Replacing obsolete equipment reduces support time, downtime and maintenance costs associated with older equipment. New equipment takes advantage of technological advances in both software and hardware to provide a platform that is more able to support customer-facing business initiatives while fortifying Alectra Utilities' cyber-security. Alectra Utilities replaces most IT hardware based on lifecycle management practices considering the expected lifespan of each category of hardware asset in order to mitigate functional obsolescence. As the end of a hardware asset's lifecycle approaches, the risk of failure increases significantly which then impacts core business processes. Upgrading control room hardware mitigates the risk of equipment failure and

prolonged outages (since the control room would not be able to respond to outages without functional communications equipment).

- **Option 2:** An alternative approach could be to move a portion or all of the utility's IT Infrastructure to be managed externally. This approach could entail significant security and maintenance risks. Beyond those risks, Alectra Utilities has no basis to believe that an out-sourcing option exists with the potential to satisfy the utility's requirements. Managing hardware externally would not allow Alectra Utilities the flexibility to make changes that require being addressed urgently, which could jeopardize the response time in dealing with issues that affect Alectra Utilities customers (outages and customer-facing system issues that are supported by IT hardware).

- **IT Security:**
  - **Status Quo:** Without investing to mitigate cyber-security gaps across the organization, Alectra Utilities would not be able to comply with modern cyber-security practices. Customer and employee information could be compromised during security attacks or breaches. For the foregoing reasons, Alectra Utilities cannot accept the status quo.
  - **Option 1 (selected option):** Alectra Utilities' planned investments are required to align with the Security Framework and to ensure Alectra Utilities' system is safeguarded from the risk of cyber-security attacks, data theft and intrusion. Alectra Utilities believes the proposed investments are the only prudent option.

VI IT Systems Investment Projects

The material investments from 2020 to 2024 that form the IT Systems investments are included in Table A18 - 14.

Table A18 - 14: Material Projects and Initiatives

Project Code	Project Name	CAPEX ($MM)
150467	CIS CC&B upgrade 2021 - 2022	$13.3
150469	ERP JD Edwards Enhancements	$8.2
150453	CIS CC&B Modifications(Regulatory Enhancements)	$5.5
102098	Client Computing	$4.9
150325	CIS CC&B Enhancements	$4.9
102263	Work Force Management / Mobile Dispatch	$4.7
102157	Server Refresh	$3.4
150573	Oracle ULA Extension 2020	$3.0
150392	Storage Upgrade	$2.3
150463	Customer Self Service Portal Enhancements 2019	$1.1

Appendix A19 - Fleet Renewal

I Overview

Alectra Utilities requires trucks, vehicles and equipment to perform work, and to transport materials as well as employees to and from job sites. The Fleet Renewal investments maintain the vehicles, trailers, and other equipment necessary to support system capital and maintenance work across Alectra Utilities' distribution system.

Although Alectra Utilities does not plan to increase the size of its fleet during the DSP period, it must replace a significant population of vehicles that have surpassed their typical useful life. As of 2018, over 64 percent of vehicles in the utility's fleet had surpassed their useful lives. As such, significant capital investments will be required in future years to bring the vehicle fleet to normal operating conditions to ensure vehicle availability to support operations, reduce potential safety risks to employees and public.

As discussed in Section 2 below, Alectra Utilities annually assesses its fleet based on a defined set of criteria designed to ensure that the cost to operate and maintain each vehicle is less than a captial and operating costs of a replacement vehicle, and that Alectra Utilties complies with all statutory regulations. Alectra Utilities also considers emissions and fuel consumption of the new vehicles compared to the ones being replaced. The planned Fleet Renewal investments will ensure that Alectra Utilities can respond to customer needs promptly, manage system reliability, and mitigate safety and environmental risks.

Table A19 - 1: Fleet Renewal Investment Expenditures, Drivers and Outcomes

	Historical Spending				Bridge	Forecast Spending				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$7.5	$4.3	$3.2	$6.7	$8.5	$8.9	$9.5	$9.9	$10.3	$10.2
Primary Driver:	System capital and maintenance work support									
Secondary Driver:	Business operational efficiency									
Investment Outcomes:	Customer Value, Safety, Reliability, Environment and Efficiency									

II Investment Description

During the DSP period, Alectra Utilities' planned fleet investments are focused on renewing vehicles that are either in poor condition, have high mileage/engine usage or have surpassed their typical useful life. Alectra Utilities does not propose to increase the size of the utility's fleet in this period.

Alectra maintains a fleet of 560 vehicles, 156 trailers, and other miscellaneous equipment to ensure safe and reliable vehicles for employees to perform their daily activities. Alectra Utilities' has garages in Markham, Mississauga, Brampton, St. Catharines, Guelph and Hamilton. The garages in Hamilton and Mississauga operate with extended hours of operation to provide Alectra Utilities with more flexibility in managing its fleet inventory, maintenance and repairs.

Alectra Utilities' fleet consists of:

- Heavy-duty vehicles;
- Medium-duty vehicles;
- Light-duty vehicles;
- Trailers; and
- Fleet equipment (e.g., forklifts, generators, and compressors).

Heavy-duty and medium-duty vehicles are the primary means of transporting equipment and materials to and from job sites. Light duty vehicles facilitate the engineering, management and planning functions of the utility. Trailers mainly provide storage for equipment at work sites. Fleet equipment is used to perform lifting, towing and are used mainly by operations and stores departments at Alectra Utilities.

As discussed in Section 3 below, a significant number of vehicles in Alectra Utilities' fleet have deteriorated to unacceptable levels. These vehicles pose safety risks for employees and the general public and must be replaced. To the extent that they are unable to fulfil their operational functions, either partially or entirely, these deteriorated vehicles negatively impact Alectra Utilities' ability to serve its customers. Replacing these vehicles is the focus of Alectra Utilities' fleet investments during the 2020-2024 DSP period.

Table A19 - 2 identifies the quantity and the types of vehicles and other assets that Alectra Utilities plans to replace through Fleet Renewal investments during the DSP period.

Table A19 - 2: Planned Fleet Renewal Investment by Vehicle Type

Vehicle Type	2020		2021		2022		2023		2024		2019-2024 Total	
	No.	CAPEX ($MM)	No.	CAPEX ($MM)	No.	CAPEX ($MM)	No.	CAPEX ($MM)	No.	CAPEX ($MM)	No.	CAPEX ($MM)
Heavy Duty Vehicles	8	3.5	15	6.8	14	5.7	12	6.3	10	5.3	**59**	**27.6**
Medium Duty Vehicles	12	1.6	11	1.2	9	1.6	6	1.0	7	2.0	**45**	**7.4**
Light Duty Vehicles	61	2.7	16	0.8	41	1.9	38	1.7	33	1.6	**189**	**8.7**
Equipment	6	0.9	3	0.5	3	0.6	9	0.8	9	0.9	**30**	**3.7**
Trailers	0	0.0	1	0.1	0	0.0	8	0.4	8	0.3	**17**	**0.8**
Shop Equipment and Tools	5	0.2	3	0.1	3	0.1	2	0.1	5	0.1	**18**	**0.6**
Total	**92**	**8.9**	**49**	**9.5**	**70**	**9.9**	**75**	**10.3**	**72**	**10.2**	**358**	**48.8**

The planned investments reflect a set of objectives and drivers, ranging from the condition of existing vehicles to external regulatory and safety requirements. Table A19 - 3 outlines the objectives and drivers of the utility's planned fleet investments.

Table A19 - 3: Fleet Renewal and Sustainment Objectives and Drivers

Objectives	Drivers of Replacement Investments
Alectra Utilities’ fleet replacement and sustainment objectives are to: • Identify vehicle replacements required to ensure adequate support for capital work, maintenance and corporate travel requirements on an annual basis • Ensure that Alectra Utilities’ vehicle replacement criteria are aligned with utility best practices, vehicle manufacturer requirements and applicable industry standards • Ensure vehicle specification standards appropriate for each vehicle class are established to reduce inventory requirements, streamline vehicle maintenance and expedite delivery timelines • Ensure that Alectra Utilities’ fleet operates in compliance with all appropriate federal, provincial, and municipal legislations, and specific licences • Establish and maintain a fleet that can meet existing and future geographic challenges and operating environments • Continue to assess, investigate and evaluate efficiencies and benefits of fleet inventory with vehicles powered by alternative sources of energy • Ensure alignment to support Alectra Utilities’ Environmental and Sustainability Development initiatives	Alectra Utilities identifies specific investments based on the following factors, as applicable to the different classes of vehicles, trailers, and other equipment that are the subject of the plan: • Manufacturing Standards • Industry Standards • Construction and Operating Standards • Vehicle Operational Conditions • Vehicle Age • Vehicle Total Mileage • Highway Traffic Act • Canadian Motor Vehicle Safety Standards • All related Canadian Safety Association standards, specifically those that relate to aerial devices and hydraulic equipment • Motor Vehicle Inspection Station requirements • Infrastructure Health and Safety Association of Ontario, where applicable • Corporate Health and Safety and Environmental Policies

Alectra Utilities annually assesses its trucks and vehicles based on the replacement assessment criteria that focus on vehicle condition, age, mileage, engine hours and operational requirements as defined within Table A19 - 4 below.

Table A19 - 4: Vehicle Renewal Assessment Criteria

Fleet Class	Renewal Assessment Criteria
Light Duty Vehicles:	• Assessed at 7 years and every year after, and/or high mileage (excess of 250,000 km) • Replacement schedule: at 7 years, (250,000 km).
Medium Duty Vehicles	• Assessed at 10 years and every year after, and/or high mileage (excess of 250,000 km) • Replacement schedule: at 10 years, (250,000 km).
Heavy Duty Vehicles:	• Assessed at 12 years' service, and every year after, and/or high mileage (excess of 500,000 km) • High engine hours (excess of 12,000 engine hours) • Replacement schedule: at 15 years, (500,000 km or 12,000 hrs.)
Trailers:	• Trailer replacement will follow the same core principles as the vehicle replacement criteria with the following differences: • Assessed at 15 years' service • When assessing trailer conditions, trailers will be refurbished rather than replaced. • Where trailers cannot be refurbished due to application change or condition, trailers will be flagged for replacement. • Replacement/Refurbishment: 15 years.

2.1 Assessing Opportunities to Reduce Fleet Size

As discussed further in Section 4.4, Alectra Utilities also conducts additional screening to ensure the vehicle being replace is still required or if a different type a vehicle is required in the event operational requirements may have changed. This screening occurs annually and prior to ordering new vehicles. When a vehicle is assessed, Alectra considers whether the actual vehicle can be disposed of rather than replaced, based on usage or operational effectiveness.

Alectra Utilities does not believe that it can prudently reduce the size of the utility's total fleet. Alectra Utilities has engaged Mercury Associates and a vehicle utilization study is currently underway. Alectra Utilities plans to continue assessing opportunities to minimize the costs of its fleet while maintaining the level of service and safety that the utility and customers require.

2.2 Garage Management System

During the DSP period, Alectra Utilities plans to implement a Garage Management System (GMS) which will allow the utility to manage its fleet information more efficiently and effectively. The system will allow Alectra Utilities to manage its resources, inventory levels and vehicle preventive maintenance schedules more efficiently. The GMS system will create detailed usage reports on parts, labour and inventory, as well as track and consolidate all costs from Alectra Utilities' ERP system. Costs tracked will include those incurred from a third-party maintenance providers and/or internal fleet operational centres at the individual vehicle and equipment level. The capital expenditure associated with this GMS software is included in Appendix A18 – Information Technology Systems.

2.3 Summary of Investment Outcomes and Benefits

Table A19 - 5 summarizes the outcomes and benefits associated with the Fleet Renewal investment.

Table A19 - 5: Investment Outcomes and Benefits

Investment Benefits	Reasoning and Investment Benefits
Customer Value	Working and operational vehicles ensure that Alectra Utilities can manage its commitment to customers by getting to work locations on-time and effectively address issues on-site.
Reliability	Contributes to Alectra Utilities' system reliability by ensuring work crews have the necessary vehicles and equipment to perform distribution work when required on a 24/7 basis.
Safety	Contributes to the safety of Alectra Utilities' operations by minimizing safety risks to crews and to the public.
Environment	Contributes to Alectra Utilities' environmental performance by reducing GHG emissions associated with fleet fuel consumption by: • Utilizing hybrid and electric vehicles where possible; and • Implementation of anti-idling technology and GPS reporting.
Efficiency	Through the replacement of fleet assets, Alectra Utilities can realize efficiency savings in several ways: • Via reduction in total life-cycle costs, including a reduction in maintenance costs, associated with new vehicles • Via reduction in fuel costs, due to the improved fuel economy of new vehicles, along with the utilization of hybrid and electric vehicles and idle-reduction technologies New Alectra Utilities vehicles will align with the utility's current-state processes and practices, and new vehicle specifications allowing the utility to avoid the cost associated with maintaining vehicles with different capabilities and maintenance requirements.

III Investment Drivers and Need

3.1 Purpose

The planned Fleet Renewal investments are driven by the condition of the utility's existing fleet, and by the operational needs of the distribution system. Both drivers are discussed in the following subsections.

3.1.1 Condition of Existing Fleet

Alectra Utilities' fleet consists of different types of trucks and vehicles that are each designed for specific work purposes. At the job site, truck and vehicle uses include:

- Lifting and positioning material;
- Storing material;
- Preparing material for installation; and
- Planning and coordinating work.

Fleet vehicles must be available to support these functions in a safe, reliable, and operationally efficient manner.

As shown in Table A19 - 6, a significant portion of Alectra Utilities' fleet is due for replacement. This figure shows the proportion of Alectra Utilities vehicles that are still in service but are either due for replacement (labelled "Current") or past-due ("Overdue"), by the utility's fleet renewal assessment criteria. Table A19 - 6 provides the percentage of vehicles purchased between 1999 and 2016 replacement status. In effect, this table shows that:

- Over 51% of vehicles purchased between 1999 and 2016 are overdue for replacement.
- Over 28% of vehicles purchased between 1999 and 2016 are currently do for replacement.

Table A19 - 6: Alectra Utilities Fleet Replacement Status Table

Model Year	Current Replacement Need	Overdue Replacement Year
1990	0.00%	0.13%
1999	0.00%	0.40%
2000	0.00%	0.93%
2001	0.00%	1.06%
2002	0.00%	1.19%
2003	0.00%	0.93%
2004	0.00%	3.17%
2005	0.00%	1.06%
2006	0.00%	6.22%
2007	0.00%	3.57%
2008	0.00%	12.96%
2009	0.00%	6.75%
2010	0.00%	13.62%
2011	4.10%	0.00%
2012	6.08%	0.00%
2013	3.84%	0.00%
2014	4.76%	0.00%
2015	5.42%	0.00%
2016	4.10%	0.00%
All Vehicles	**28.30%**	**51.99%**

Table A19 - 7: Alectra Utilities Vehicles 2020 – 2024 Replacement Age

Fleet Types (2020-2024)	Replacement Criteria (Years)	Average Age at Replacement Period (Years)
Trailers Replacement	15	19.5
Fleet Equipment Replacement	15	21.8
Light Duty Vehicles Replacement	10	10.6
Medium Duty Vehicles Replacement	12	12.3
Heavy Duty Vehicle Replacement	15	17

Alectra Utilities fleet capital expenditures between 2020 and 2024 will focus on vehicles that have reached or surpassed their end of life. Alectra Utilities medium duty vehicles replacement criteria is 10 years and heavy-duty vehicles is 15 years. Vehicles being replaced between 2020 and 2024 were manufactured in 2010 or earlier. Table A19 - 7 sets out the number of vehicles that Alectra

Utilities forecasts will be at or beyond their end of life in each year of the DSP period. As shown in Table A19 - 2 above, Alectra Utilities does not propose to replace all of the vehicles identified in Table A19 - 8 below, to help mitigate rate increases.

Table A19 - 8: Summary of Alectra Utilities Vehicles at or Beyond End of Life

Alectra Utilities Vehicle Replacement Overdue by Type			
Years	**Light Duty**	**Medium Duty**	**Heavy Duty**
2020	114	31	13
2021	77	22	18
2022	83	18	14
2023	53	12	11
2024	33	7	4
Total	**360**	**90**	**60**

As vehicles deteriorate with use, age and exposure to weather conditions, Alectra Utilities has experienced an increased risk of potential safety issues as a result of structural failures, component failure as well as vehicle electrical faults. Vehicle failures and faults are typically triggered by a number of factors, including corrosion. Alectra Utilities' fleet vehicles are continuously used throughout the year and continuously exposed to environmental conditions including severe weather and rugged working site elements.

Figure A19 - 1 illustrates some examples of fleet vehicle degradation modes, including corrosion/rusting, leaking and exterior damage.

Figure A19 - 1: Examples of Alectra Utilities' Fleet Vehicle Degradation

Vehicle age, use, salt on city streets are the main reasons for increasing corrosion conditions as corrosion damages and weakens the frame of the truck or vehicle over time. The frame is the main structure of a vehicle to which all running gears are secured, and supports the entire weight of the vehicle and is fastened to the wheels, suspension, and steering components. Severe rust to the frame can lead to breaks while under load (for example, during a lift operation, pulling cable, or material loading). Frame weakness can also decrease the ability of the vehicle to withstand crashes, thus jeopardizing the safety of the operators and the general public.

Corrosion may also occur on components that are critical to the operation of the vehicle, such as transmission and brake lines, that are often not observable without substantial teardown. Rust on these components results in weak spots that have the potential to rupture and leak, and cause failures while in use. For example, a transmission line rupture could result in a seized transmission. Transmission failure of heavy-duty trucks and vehicles introduces significant risk to the operators' safety and the safety of the general public. Similarly, brake line failures introduce safety risks due to loss of control and ability of the operator to appropriately stop the truck or vehicle.

Regular use of the fleet assets over time can lead to the failure of critical components that are not readily serviceable or observable by maintenance staff. Components such as the hydraulic hoses running through an aerial bucket truck, for instance, cannot be directly inspected at service intervals. As these hoses age, they become less flexible and more brittle. Hose failure results in hydraulic fluid leaking into the environment and could potentially result in stranding an employee operating a bucket at significant heights. Rescuing an employee from an aerial bucket truck presents a potential risk to the employee in the bucket as well as other field employees and the general public in the vicinity.

As vehicles deteriorate, components designed to protect the vehicles' electrical circuitry can become compromised as the vehicle ages and deteriorates with regular use, leading to potential electrical failures. The risk of vehicle electrical circuitry failure increases with the use and age of the truck or vehicle. Vehicle electrical failures introduce the risk of failing auxiliary safety lighting systems and onboard equipment which are mandatory to protect the public and also permit staff to perform the work safely.

Timely vehicle replacement is necessary to avoid undue vehicle downtime and associated negative impacts on customer response time and employee productivity. Trucks and vehicles are "the workplace" for over 60% of Alectra Utilities' workforce. Providing and maintaining a safe and reliable fleet is key to building a better workplace for Alectra Utilities' employees and providing them with the tools required to provide service to Alectra Utilities' customers.

As shown in Table A19 - 4, Alectra Utilities uses the age of a vehicle to trigger more detailed assessment of the vehicle's condition. Age is a good preliminary measure of condition since utility vehicles are subject to consistent wear and deterioration which negatively impacts their safety, reliability and operational efficiency. Alectra Utilities has determined that once the age profile of a truck or vehicles surpasses the ages identified in Table A19 - 4, their reliability is typically compromised, and may pose risks to the employees and public safety and reliability of distribution work. Furthermore, once the average age of the fleet exceeds the age within the specified replacement schedule, Alectra Utilities has experienced increased costs for the vehicle-related parts and services and vehicle down time at the shop. The utility's average annual operating budget of $3.2MM has proven insufficient to maintain and repair 560 vehicles, 156 trailers, and other miscellaneous equipment. As shown in Table A19 - 9, the actual cost of the utility Vehicle Maintenance and Repairs budget has increased by $0.9MM annually on average, due in part to material and labour to keep end of life vehicles in operations due to the lack of required capital expenditures in previous years. Alectra Utilities expects that the vehicle-related operating costs and down-time will continue to escalate as the average age of the fleet increases and end of life vehicles are not replaced. Investment in fleet sustainment and renewal is required to optimize the total cost of ownership while supporting Alectra Utilities' work and travel requirements.

Table A19 - 9: Vehicle Maintenance and Repairs (Actual vs. Budget) for 2017 and 2018 ($MM)

2017			2018		
Actual	Budget	Variance	Actual	Budget	Variance
$4.1	$3.3	$(0.9)	$4.2	$3.2	$(1.0)

3.1.2 Operational Needs

As operational needs and work requirements evolve with standards and technologies, specific vehicle and equipment configurations are required to be updated such as higher and heavier hydro poles requiring bigger trucks with longer and higher capacity booms. Alectra Utilities is also installing underground infrastructure within its service territory which requires differently designed vehicles to handle longer and heavier underground cabling. Larger capacity transformers also require vehicles with higher lifting capacity and finally, smaller vehicles that can accommodate work within higher population density areas are required. As part of the planned vehicle replacements, Alectra Utilities will work closely with Operations and Manufactures to procure vehicles that are better position to support operational needs and work requirements in the years to come.

The primary driver of the fleet renewal investment is to provide trucks and vehicles necessary to support Alectra Utilities' capital and maintenance work and 24/7 trouble response. The secondary driver of the investments is business operations efficiency, as the renewal investment will ensure that Alectra Utilities' continues to deliver reliable and timely services to customers in an efficient manner.

Table A19 - 10 provides further details of the primary and secondary drivers of the fleet renewal investment.

Table A19 - 10: Fleet Renewal Investment Drivers

Investment Driver	Reasoning and Investment Benefits
System Capital and Maintenance Work Support	This investment is designed to support Alectra Utilities personnel to access and work on the distribution system, and provide the ability to respond to urgent daily operational work in a timely manner.
Business Operations Efficiency	This investment is designed to introduce business efficiencies in respect to getting crews to sites in a more cost efficient manner, due to savings in fuel and maintenance costs enabled by updated fleet assets.

IV Investment Timing and Pacing

4.1 Summary of Expenditures

Table A19 - 11 provides the year-over-year breakdown of overhead asset renewal investments, including the historical period from 2015-2018, the bridge year in 2019, and the forecast period from 2020-2024.

Table A19 - 11: Historical and Proposed Fleet Renewal Investment 2015-2024

	Historical Spending				Bridge	Forecast Spending				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$7.5	$4.3	$3.2	$6.7	$8.5	$8.9	$9.5	$9.9	$10.3	$10.2

4.2 Historical Expenditures (2014-2019)

Historical fleet expenditures between 2015 and 2019 total $30.2MM. During the historical period, fleet investments varied due to two factors: (i) differences between the fleet management practices and policies of the four predecessor utilities, and (ii) deferred expenditures to accommodate high-priority, non-discretionary capital investments and to ensure effective integration of the five predecessor utilities' fleets.

The predecessor utilities each employed their own fleet management approaches. Alectra Utilities developed a consolidated vehicle replacement process following the merger. Expenditures in 2018 were the first to be based on the utility's consolidated approach. Most of the predecessor utilities vehicle replacement criteria resulted in vehicles staying in operations based on manufactures replacement guidance, poor vehicle conditions, other utilities replacement criteria, and recommended industry best practices. Alectra Utilities vehicle replacement criteria is more in line with manufactures replacement guidelines, other utilities replacement criteria, and recommended industry best practices. Table A19 - 12 captures the vehicles replacement criteria of the initial four predecessor utilities and Alectra Utilities.

Table A19 - 12: Alectra Legacy Utilities Vehicle Replacement Criteria's Summary:

Vehicle Class	HOBNI	PowerStream	Horizon Utilities	Enersource	Alectra Utilities
Cars	10 yrs/ 200,000 km	200,000 km	6-8 yrs/ 150,000 km	5 yrs	7 yrs/ 175,000 km
Hybrid Vehicles	8 yrs/ 200,000 km	200,000 km	6-8 yrs/ 150,000 km	5 yrs	7 yrs/ 175,000 km
Pickups	10 yrs/ 200,000 km	275000 km	6-8 yrs/ 150,000 km	5 yrs	7 yrs/ 200,000 km
Pickups RGVW 4500KG.		250,000 km	6-8 yrs/ 150,000 km	8 yrs	7 yrs/ 200,000 km
Passenger Vans	10 yrs/ 200,000	200,000 km	6-8 yrs/ 150,000 km	5 yrs	7 yrs/ 200,000 km
S.U.V.	10 yrs/ 200,000	200,000 km	6-8 yrs/ 150,000 km	5 yrs	7 yrs/ 200,000 km
Work Vans	10 yrs/ 200,000	250,000 km	10 yrs/ refurbish	8 yrs	10 yrs/ 200,000 km
Tractor	15 yrs/ 10,000 hrs/ 400,000 km	250,000 km/ 12,000 hrs	16-19 yrs/ 15,000 hrs/ 200,000 km	12 yrs	15 yrs/ 12,000 hrs/ 250,000 km
Digger Derrick	10 yrs/ 10,000 hrs/ 200,000 km	250,000 km/ 12,000 hrs	16-19 yrs/ 15,000 hrs/ 200,000 km	12 yrs	10 yrs/ 12,000 hrs/ 200,000 km
Hiab (Crane Truck)	20 yrs/ 10,000 hrs/ 200,000 km	250,000 km/ 12,000 hrs	16-19 yrs/ 15,000 hrs/ 200,000 km	8 yrs	15 yrs/ 12,000 hrs/ 200,000 km
Trailers	15 yrs	15 yrs	10 yr assessment/ replace or refurbish	15 yrs	15 Years
Tension Machine	12 yrs/ 10,000 engine hrs	15 yrs	10 yrs assessment/ replace or refurbish	15 yrs	10 yrs/ 10,000 hrs
Lift Trucks	15 yrs/ 10,000 hrs	15 yrs	15 yrs	15 yrs	15 yrs
Pole Trailer/ Flatbed	15 yrs/ 400,000 km	20 yrs	10 yr assessment/ replace or refurbish	15 yrs	10 yr replace or refurbish/ 15 yr replace
Enclosed Trailer	15 yrs	15 yrs	10 yr assessment/ replace or refurbish	15 yrs	15 yrs
Single Bucket	10 yrs/ 10,000 hrs/ 250,000 km	250,000 km/ 12,000 hrs	16-19 yrs/ 15,000hrs/ 200,000 km	8 yrs	15 yrs/ 12,000 hrs/ 225,000 km
Double Bucket	10 yrs/ 10,000 hrs/ 250,000 km	250,000 km/ 12,000 hrs	16-19 yrs/ 15,000hrs/ 200,000 km	12 yrs	15 yrs/ 12,000 hrs/ 225,000 km
Dumps		250,000 km/ 12,000 hrs.	16-19 yrs/ 15,000hrs/ 200,000 km	8 yrs	10 yrs/ 15,000 hrs/ 200,000 km

In the historical period, and particularly in 2016 and 2017, Alectra Utilities and its predecessor utilities deferred some fleet expenditures that would otherwise have been required to maintain the utilities' respective fleets. In this period, Alectra Utilities deferred all but the most critical fleet investments, in order to ensure and confirm that the replacements would not exceed the needs of the consolidated entity. It would likely have been imprudent for Alectra Utilities or its predecessors to invest in new vehicles if one of the other legacy utilities owned the vehicles necessary to meet the newly-formed utility's needs. Following the merger, some practices were harmonized, reducing the need to replace planned vehicles by legacy utilities during 2017 and 2018 as per Table A19 - 13 below.

Table A19 - 13: Vehicle Reductions Between 2017 and 2018 Summary ($MM)

Vehicle Reductions	Legacy Utility	2017	2018
Dump Truck Not Replaced	Central - South	$0.1	$0.0
Dump Truck Not Replaced	Central - South	$0.1	$0.0
Dump Truck Not Replaced	Central - South	$0.1	$0.0
Pickup Truck Not Replaced	Central - South	$0.1	$0.0
Three Engineering Vehicles Not Replaced	West	$0.1	$0.0
Vacuum Truck Not Replaced	Central - North	$0.5	$0.6
Total		**$1.0**	**$0.6**

4.3 Future Expenditures (2020-2024)

Forecast expenditures between 2020 and 2024 totals $48.8MM. This expenditure is needed to bring the utility's vehicle fleet to ensure vehicles are available and in condition necessary to support operations, reduce potential safety risks to employees and public, and to operate efficiently.

Table A19 - 14 provides the year-over-year breakdown in terms of units replaced and expenditures across the fleet vehicle categories. (This table is identical to Table A19 – 2 above).

Table A19 - 14: Planned Fleet Renewal Investment by Vehicle Type

Vehicle Type	2020		2021		2022		2023		2024		2019-2024 Total	
	No.	CAPEX ($MM)	No.	CAPEX ($MM)	No.	CAPEX ($MM)	No.	CAPEX ($MM)	No.	CAPEX ($MM)	No.	CAPEX ($MM)
Heavy Duty Vehicles	8	3.5	15	6.8	14	5.7	12	6.3	10	5.3	59	27.6
Medium Duty Vehicles	12	1.6	11	1.2	9	1.6	6	1.0	7	2.0	45	7.4
Light Duty Vehicles	61	2.7	16	0.8	41	1.9	38	1.7	33	1.6	189	8.7
Equipment	6	0.9	3	0.5	3	0.6	9	0.8	9	0.9	30	3.7
Trailers	0	0.0	1	0.1	0	0.0	8	0.4	8	0.3	17	0.8
Shop Equipment and Tools	5	0.2	3	0.1	3	0.1	2	0.1	5	0.1	18	0.6
Total	**92**	**8.9**	**49**	**9.5**	**70**	**9.9**	**75**	**10.3**	**72**	**10.2**	**358**	**48.8**

Relative to the utility’s needs, the planned fleet investments are conservative. To minimize the impact on ratepayers, Alectra Utilities has decided to spend less on Fleet Renewal during the DSP period than prescribed by its vehicle replacement criteria. As shown in Table A19 - 15, if Alectra Utilities were to strictly follow its vehicle replacement criteria, the current condition its fleet would result in expenditures of approximately $12.5MM per year throughout the DSP period.

Table A19 - 15: Vehicle Replacement Criteria vs. Proposed DSP Expenditures

Alectra Utilities Fleet Capital Expenditure ($MM)	2020	2021	2022	2023	2024	Total
Needs Determined Through Condition and Replacement Criteria	$12.8	$12.4	$12.8	$11.9	$13.2	$63.1
Proposed	$8.9	$9.5	$9.9	$10.3	$10.2	$48.8
Difference Between Needs and Proposed	**$3.9**	**$2.9**	**$2.9**	**$1.6**	**$3.0**	**$14.3**

4.4 Investment Pacing and Prioritization

When planning and executing Fleet Renewal investments, Alectra Utilities considers several factors as part of an ongoing screening process for fleet assets. To execute and sufficiently pace and prioritize the Fleet Renewal investment, Alectra Utilities implemented a first pass screening process which includes an assessment of the vehicle type, usage and age. At this time, the vehicles' mileage, engine hours, utilization, and Power Take Off ("PTO") hours are documented. This assessment provides Alectra Utilities a baseline to initiate the capital replacement assessment process. During this time, the vehicle utilization is also examined and internal discussions take place with various business units on the vehicle requirement. Alectra Utilities examines the possibility to re-allocate vehicles to maximize utilization as well as considers replacement options (e.g., like-for-like vehicle replacement or revision of vehicle to match evolved business requirements).[166]

Vehicle refurbishment is also considered, particularly for large and higher investment vehicles such as bucket, digger, and derrick trucks.

[166] Trucks and vehicles may be renewed by different models or types depending on updated operation processes, corporate initiatives and customer requirements.

4.5 Execution Approach

Once the vehicle replacements have been confirmed and approved, vehicles are sourced and purchased based on Alectra Utilities Procurement Policy and Processes. Alectra Utilities previously issued annually a Request for Proposal ("RFP"). The utility then would award purchases based on the RFP scope and selection criteria. Instead of annual procurements, Alectra Utilities will be issuing an RFP for its 2020 to 2024 vehicle replacements, working directly with vehicle manufactures to maximize its purchasing volume and obtain more favorable pricing and terms.

V Options Analysis

Alectra Utilities has considered the following intervention options concerning Fleet Renewal investments:

5.1 Status Quo / Run to Failure
5.2 Replacing Portions of Heavy-Duty Vehicles instead of full replacement
5.3 Replacing Medium- and Heavy-Duty Vehicles with Demonstration Vehicles Instead of New
5.4 Replacing Fleet Vehicles Based on Alectra Utilities Renewal Criteria

5.1 Status Quo / Run to Failure

Under the status quo option, Alectra Utilities would continue to utilize existing and deteriorating fleet vehicles, which will continue to expose Alectra Utilities employees as well as the general public to potential safety hazards should these vehicles fail and vehicle availability to support daily operations. Furthermore, system reliability will be impacted as Alectra Utilities crews risk prolonged transport to outage sites should trucks and vehicles fail to function.

As described in Section 4.5, Alectra Utilities uses an annual procurement process that maximizes economies of scale from planned procurement of fleet vehicles. Alectra Utilities planned approached to replacing its fleet, ensures vehicle specifications standardization, better pricing and plan for long delivery lead times on mid and heavy duty vehicles that could take up to 18 months to manufacture. In addition to the very serious safety risks associated with a run to failure approach, Alectra Utilities (and ratepayers) would lose some of the cost-efficiency that results from planned procurement.

5.2 Replacing Portions of Heavy-Duty Vehicles Instead of Full Replacement

Replacing portions of a heavy-duty vehicle is a viable option and one that predecessor and Alectra Utilities have exercised in the past with some success, and Alectra Utilities will continue to consider this as an option. The challenge with this option is the overall vehicle condition that may not make financial or operating sense, access and availability of material replacements and long waiting periods to get the vehicles back in service. Vehicle replacements need to be planned due to manufacturing scheduling, long delivery timeframes and obtain better pricing.

5.3 Replacing Medium- and Heavy-Duty Vehicles with Demonstration Vehicles Instead of New

Replacing medium- and heavy-duty vehicles with demonstration models instead of new vehicles would theoretically help mitigate the cost of needed Fleet Renewal investments. However, it is difficult to locate demonstration vehicles that meet the operational criteria.

Alectra Utilities cannot rely on this approach, since the availability and quality of demonstration vehicles cannot be planned or depended upon. Further, in the event that Alectra Utilities can locate a satisfactory demonstration vehicle that is available for purchase, the utility does not believe that a sufficient volume will be available to address its needs. Alectra Utilities rejected this approach because it would be imprudent and unrealistic to rely on the availability of demonstration vehicles.

5.4 Replacing Fleet Vehicles Based on Alectra Utilities Renewal Criteria

Alectra Utilities' planned investments are based on the level prescribed by the criteria described in Section 2 above. As described in Section 4.3, Alectra Utilities has proposed to spend less on Fleet Renewal during the DSP period than prescribed by its vehicle replacement criteria.

Alectra Utilities believes that the level of Fleet Renewal investment in the DSP is the minimum needed to mitigate the risks posed by the current condition of the utility's fleet.

Table A19 - 16 outlines the risk levels concerning probability and impact, based upon the current condition and performance of the fleet population, as well as the necessary actions needed to mitigate these risks. Based on this analysis, it is necessary for Alectra Utilities to execute the investment as proposed over the DSP period.

Table A19 - 16: Risks for Not Replacing Vehicles Based on the Replacement Criteria

Risk	Probability (High/Med/ Low)	Impact (High/Med/ Low)	Expected Outcomes
Vehicle availability and reliability	High	High	Deteriorated vehicles cannot perform well, required more frequent repair and maintenance spend more time in the shop or down for long period of time, reducing the number of vehicles availability and reliability to support customers.
Employee and public safety	High	Med	Vehicles in poor condition create potential safety risks for employees and the public. Additional resources and operating expenditures are required to keep such vehicles operational.
Increasing systems outages response timelines to support customers	High	High	Vehicle down time due to required repairs and increased maintenance may limit Alectra Utilities' ability support customers and could increase the duration of system outrages.

VI Investment Projects

There are no material projects and initiatives for Fleet Renewal from 2020 to 2024.

Appendix A20 - Connection and Cost Recovery Agreements

I Overview

Through its legacy utilities, Alectra currently has 13 separate Connection and Cost Recovery Agreements ("CCRA") with Hydro One Networks Inc. (HONI) for the expansion of Transformer Station ("TS") facilities.

As per the Transmission System Code ("TSC"), HONI is required to execute CCRAs with the proponent of any connection to transmitter-owned facilities. These CCRAs includes customer load guarantees, cost responsibility, scope of work, and any initial capital contribution which reflects the forecast shortfall of transmission revenue that HONI will not recover through rates.

The CCRA utilizes initial project costs and projected incremental load (revenue) over a 25-year horizon as inputs to determine the capital contribution payment at the project in-service date. The incremental load forecast provides average monthly peak load estimates. Terms in the CCRA include a financial mechanism to compare forecast average monthly demand against actual demand, which is designed to recover a shortfall in revenue or a refund of a balance where actual demand exceeds forecast values. As such, in cases where actual demand has failed to materialize when compared to the load forecast, Alectra is required to refund the balance back to HONI.

The CCRA represents a contract between Alectra Utilities and HONI to provide payment for true-up settlements.

Alectra forecasts that the over the 2020-2024 DSP period, approximately $10.8 MM will be required for four stations where the incremental load forecasted in the CCRA document will be greater than the actual demand thereby creating a revenue shortfall for HONI and triggering a capital contribution.

Table A20 - 1 provides a summary of expenditures, drives and outcomes for CCRA contributions.

Table A20 - 1: Investment Subgroup Summary, Drivers and Outcomes

	Historical Spending				Bridge	Forecast Spending				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$54.8	$0.4	$0.0	$6.8	$1.0	$8.7	$1.6	$0.0	$0.5	$0.0
Primary Driver:	Mandated Service Obligations									
Secondary Drivers:	System Maintenance and Capital Investment Support									
Outcomes:	Customer Value, Reliability									

II Investment Description

The TSC specifies that when a load customer elects to be served by transmitter-owned connection facilities, the transmitter shall require a capital contribution from the load customer to cover the cost of the connection facility. The capital contribution may only be required to the extent that the cost of the connection facility us not recoverable in connection rates revenue. As noted above, Alectra currently has 13 separate CCRAs with HONI for the expansion of Alectra's TS facilities.

The capital contributions that Alectra must make to HONI can evolve over time. Each CCRA is originally constructed by performing an economic evaluation of the projected revenues and costs for the TS over a 25-year forecast horizon, which is used to determine the original capital contribution required for the construction and use of the respective TS. After a TS is put into service, the economic evaluation is updated for the actual costs to construct and an updated load forecast, if required. The TSC requires that a review or true-up take place at five-year intervals from the original in-service date. At these prescribed five-year intervals, the economic evaluations are updated to account for any changes to actual load experienced, and for an updated load forecast. The resulting analysis can lead to an additional contribution (i.e. if the load profile has not materialized) or a credit (i.e. if the load profile has increased).

The TSC requires that HONI carry out true-up calculations based on actual customer loads at each of the 5th, 10th, and 15th years after the in-service date of the specific facility. The 15-year true-up occurs only if the actual load at the 10-year true-up is outside of a 20% band (higher or lower) than the original load forecast used to determine the capital contribution requirement. The CCRA model makes no changes to any of the economic assumptions that were used to generate the original capital contribution, if any and for true-up purposes only the load forecast is updated for the remainder of the economic evaluation period.

Based on the true-up calculations, if the evaluation shows that the TS would generate forecast revenue shortfalls, then Alectra would be required to make a true-up payment to HONI. If, on the other hand, the evaluation generates forecast revenue gains, then Alectra would receive a credit, which would be applied against any subsequent true-up calculations, or paid out to Alectra at the last true-up calculation. Finally, when updating the actual load, the load should not be reduced for any embedded generation or conservation that may have taken place since the time of the initial evaluation.

Alectra Utilities has completed a load forecast for these stations based on the growth projections obtained from the planned developments, trend forecasting over the past five years and the CDM/DG forecast for the future years and has identified that there will be shortfall between the incremental load forecast in the CCRA and actual demand at the following TS:

- Midhurst TS
- Nebo TS
- Vansickle TS
- Goreway TS

The final contribution required at the true up may be slightly different from the calculated amount but Alectra firmly believes that these amounts will not be material.

Ultimately, the CCRA represents a contract between Alectra Utilities and HONI, under which Alectra Utilities is obligated to pay true-up settlements. In the cases noted above, Alectra and HONI will have settle based on the revised forecasts, resulting in capital contributions owing to HONI from Alectra during the DSP period. Should the load not material at a later time period, the true-up payment would substantially increase due to the discounted cash flow process.

2.1 Summary of Investment Benefits

Table A20 - 2 summarizes the outcomes and benefits associated with the Facilities investment.

Table A20 - 2: Investment Outcomes and Benefits

Investment Benefits	Reasoning and Investment Benefits
Customer Value	Ensure adequate capacity is available to supply new and existing customer load associated with increasing intensification and population and employment growth (i.e., new residential, commercial, industrial, and institutional customers) through station transformer upgrades and new substations.
Reliability	The underlying station will result in stabilized reliability for connected customers.

III Investment Drivers and Need

3.1 Purpose

The purpose of the CCRA investment is to provide cost recovery to HONI as per the agreed upon terms under instances where the actual demand for a given station does not align to the average monthly peak load estimates.

The primary driver is Mandated Service Obligations, as Alectra is mandated under the agreement to provide these payments. The secondary driver is System Maintenance and capital investment support for substation renewal and expansion work performed by HONI allows for system maintenance and capital investment activities to continue across the system.

These drivers are summarized in Table A20 - 3.

Table A20 - 3: Investment Drivers

Investment Driver	Reasoning and Investment Benefits
Primary Driver: Mandated Service Obligations	Under the terms of the CCRA, Alectra is required to provide cost recoveries back to HONI where the actual load fails to materialize at a given substation.
Secondary Driver: System Maintenance and Capital Investment Support	The underlying renewal and expansion activities performed by HONI allow for further stabilization across the system, thereby allowing for system maintenance and capital investments to continue to be executed.

The following subsections provide further details into the work that will be accomplished within this investment:

3.2 Midhurst TS

In December 2004, the construction of Midhurst TS T3/T4 was completed and was put into service. This station along with Barrie TS serves the needs in the Barrie Area.

The peak demand in Barrie continues to be lower than forecasted before Midhurst TS T3/T4 was constructed. This will result in revenue shortfall for HONI. The revenue shortfall continues largely due to government-driven conservation initiatives, natural conservation, and an impact of economic downturn that occurred in 2008 (and which has not been overcome) which have resulted in historical actual load being lower than forecasted load.

The fifteen-year anniversary true-up for Midhurst TS is due in 2020. Alectra estimates a shortfall of revenue to HONI versus the forecasted initial capital contribution. Request for financial settlement is anticipated from HONI in 2020 in the amount of $3.2MM, with the final amount and payment terms negotiated between HONI and Alectra at that time.

3.3 Goreway TS

In 2010, the construction of Goreway TS Expansion was completed and was put into service. The station currently serves Alectra Utilities customers in Brampton area.

Based on a review of the CCRA with HONI for Goreway TS on the station's five-year anniversary, Alectra and HONI determined that there had been a shortfall of revenue to HONI versus the forecasted Initial Capital Contribution. Alectra paid HONI a CCRA shortfall payment of $681,000 in 2015.

The 10-year anniversary true-up for Goreway TS Expansion is due in 2020. Alectra estimates a shortfall of revenue to HONI versus the forecasted Initial Capital Contribution and the five-year true-up settlement is estimated $5.6MM. Alectra expects a request for financial settlement from HONI in 2020, with the final amount and payment terms negotiated between HONI and Alectra at that time. The revenue shortfall continues largely due to government-driven conservation initiatives, natural conservation and an impact of economic downturn that occurred in 2008 (and which has not been overcome) which have resulted in historical actual load being lower than forecasted load.

3.4 Nebo TS

A need for new transformation capacity was identified to meet existing and future demand growth in the Stoney Creek mountain area of Hamilton in 2013. The proposed station expansion was designed to increase available capacity allocated to Alectra in conjunction with HONI Distribution who were also seeking an increase in capacity at the facility.

Based on a review of the CCRA with HONI for Nebo TS capacity upgrade of T1/T2 on the ten-year anniversary, Alectra estimates a shortfall of revenue to HONI versus the forecasted Initial

Capital Contribution. The ten-year anniversary true-up for Nebo TS expansion is due in 2023. Alectra expects a request for financial settlement from HONI in 2023, in the amount of $549,000, with the final amount and payment terms negotiated between HONI and Alectra at that time. The revenue shortfall will be largely due to government-driven conservation initiatives, natural conservation and an impact of slower growth occurring in the area which have resulted in actual load being lower than forecasted load.

3.5 Vansickle TS

Alectra is party to a CCRA with HONI dated May 2008. This agreement provided for the upgrade of the Vansickle TS on behalf of HONI for the purpose of meeting anticipated electricity load growth in St.Catharines.

A need for new transformation capacity was identified to meet existing and future demand growth in the South-West area of St.Catharines. The proposed station expansion was designed to offload Carlton TS T5/T6 that was exceeding transformation capacity as well as existing Vansickle TS facilities nearing capacity.

Based on a review of the CCRA with HONI for Vansickle TS capacity upgrade of T5/T6 on the ten-year anniversary, Alectra determined there will be shortfall of revenue to HONI versus the forecasted Initial Capital Contribution. The ten-year anniversary true-up for Vansickle TS expansion is due in 2021. Alectra estimates a shortfall of revenue to HONI versus the forecasted Initial Capital Contribution. Alectra expects a request for financial settlement from HONI in 2021, in the amount of $1.58M, with the final amount and payment terms negotiated between HONI and Alectra at that time. The revenue shortfall is largely due to government-driven conservation initiatives, natural conservation and an impact of slower ancillary growth occurring around Niagara Regional Hospital, which have resulted in actual load being lower than forecasted load.

IV Investment Timing and Pacing

4.1 Summary of Expenditures

Table A20 - 4 provides the year-over-year breakdown of CCRA investments, including the historical period from 2015-2018, the bridge year in 2019, and the DSP period from 2020-2024.

Table A20 - 4: Historical and Proposed Investment Spending

	Historical Spending				Bridge	Forecast Spending				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$54.8	$0.4	$0.0	$6.8	$1.0	$8.7	$1.6	$0.0	$0.5	$0.0

4.2 Historical Expenditures (2015-2019)

Historic 2015 expenditure included the payment made for Churchill Meadows TS, Nebo TS and Pleasant and Goreway TS expansion. Historic 2016 and 2018 payment included the CCRA payment for Holland TS and Pleasant TS respectively. In 2019, Alectra is forecasting a payment for Holland TS

4.3 Future Expenditures (2020-2024)

Future expenditures from 2020 onwards to 2024 will total $10.8 MM. These expenditures will be variable from year-to-year depending on the true-up period for each project. The 2020-2024 expenses have been derived by completing the discounted cash flow analysis using the CCRA models provided by HONI with the forecasted load growth on these stations in the next six years. The expenditure for each year is dependent on the individual station that will be trued up in that given year.

4.4 Investment Pacing and Prioritization

Pacing and prioritization of investments depends on the true-up period for the particular associated HONI project respectively.

4.5 Execution Approach

Alectra will work with HONI to provide the necessary information and will review the calculations provided by HONI for each station. Alectra will provide the necessary cost recovery to HONI at the optimal date.

V Options Analysis

There is only one option that can be considered with this investment as Alectra is obligated to comply with TSC requirements and provide cost recovery to HONI as required.

VI Investment Projects

The material investments from 2020 to 2024 that form the CCRA investments are included in Table A20 - 5.

Table A20 - 5: Material Projects and Initiatives

Project Code	Project Name	CAPEX ($MM)
151124	Goreway TS Expansion (CCRA) - 10 Yr True-Up Payment	$5.6
151125	Connection Cost Recovery Agreement (CCRA) – Midhurst TS – 15th Anniversary True-up	$3.2
151117	Vansickle TS True-up Payment	$1.6